BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: : Docket Number

ELECTRICITY MARKET DESIGN AND STRUCTURE : RM01-12-000

- x

PJM INTERCONNECTION, L.L.C. : Docket Number

ALLEGHENY ELECTRIC COOPERATIVE, INC. : RT01-2-001

ATLANTIC CITY ELECTRIC COMPANY :

BALTIMORE GAS & ELECTRIC COMPANY :

DELMARVA POWER & LIGHT COMPANY :

JERSEY CENTRAL POWER & LIGHT COMPANY :

METROPOLITAN EDISON COMPANY :

PECO ENERGY COMPANY :

PENNSYLVANIA ELECTRIC COMPANY :

PPL ELECTRIC UTILITIES CORPORATION :

POTOMAC ELECTRIC POWER COMPANY :

PUBLIC SERVICE ELECTRIC & GAS COMPANY :

UGI UTILITIES, INC. :

- x Docket Number

ALLEGHENY POWER : RT01-10-000

- x

AVISTA CORPORATION : Docket Number
MONTANA POWER COMPANY : RT01-15-000
NEVADA POWER COMPANY :
PORTLAND GENERAL ELECTRIC COMPANY :
PUGET SOUND ENERGY, INC. :
SIERRA PACIFIC POWER COMPANY :

- x Docket Number

SOUTHWEST POWER POOL, INC. : RT01-34-000

- x

AVISTA CORPORATION : Docket Number
BONNEVILLE POWER ADMINISTRATION : RT01-35-000
IDAHO POWER COMPANY :
MONTANA POWER COMPANY :
NEVADA POWER COMPANY :
PACIFICORP :
PORTLAND GENERAL ELECTRIC COMPANY :
PUGET SOUND ENERGY, INC. :
SIERRA PACIFIC POWER COMPANY :

- x

GRIDFLORIDA, LLC : Docket Number
FLORIDA POWER & LIGHT COMPANY : RT01-67-000
FLORIDA POWER CORPORATION :
TAMPA ELECTRIC COMPANY :

- x

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CAROLINA POWER & LIGHT COMPANY : Docket Number

DUKE ENERGY CORPORATION : RT01-74-000

SOUTH CAROLINA ELECTRIC & GAS COMPANY :

GRIDSOUTH TRANSCO, LLC :

- x Docket Number

ENTERGY SERVICES, INC. : RT01-75-000

- x Docket Number

SOUTHERN COMPANY SERVICES, INC. : RT01-77-000

- x

CALIFORNIA INDEPENDENT SYSTEM OPERATOR : Docket Number

CORPORATION : RT01-85-000

- x

BANGOR HYDRO-ELECTRIC COMPANY : Docket Number

CENTRAL MAINE POWER COMPANY : RT01-86-000

NATIONAL GRID USA :

NORTHEAST UTILITIES SERVICE COMPANY :

THE UNITED ILLUMINATING COMPANY :

VERMONT ELECTRIC POWER COMPANY :

ISO NEW ENGLAND, INC. :

- x Docket Number

MIDWEST INDEPENDENT SYSTEM OPERATOR : RT01-87-000

- x Docket Number

ALLIANCE COMPANIES : RT01-88-000

- x

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NSTAR SERVICES COMPANY : Docket Number

: RT01-94-000

- x

NEW YORK INDEPENDENT SYSTEM OPERATOR, INC.: Docket Number

CENTRAL HUDSON GAS & ELECTRIC CORPORATION : RT01-95-000

CONSOLIDATED EDISON COMPANY OF NEW YORK, :

INC. :

NIAGARA MOHAWK POWER CORPORATION :

NEW YORK STATE ELECTRIC & GAS CORPORATION :

ORANGE & ROCKLAND UTILITIES, INC. :

ROCHESTER GAS & ELECTRIC CORPORATION :

- x Docket Number

PJM INTERCONNECTION, L.L.C. : RT01-98-000

- x Docket Number

REGIONAL TRANSMISSION ORGANIZATIONS : RT01-99-000

- x Docket Number

REGIONAL TRANSMISSION ORGANIZATIONS : RT01-100-000

- x Docket Numbers

ARIZONA PUBLIC SERVICE COMPANY : RT02-1-000

EL PASO ELECTRIC COMPANY : EL02-9-000

PUBLIC SERVICE COMPANY OF NEW MEXICO :

TUCSON ELECTRIC POWER COMPANY :

WESTCONNECT RTO, LLC :

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Commission Meeting Room 2-C

Federal Energy Regulatory

Commission

888 First Street, N.E.

Washington, D.C.

Wednesday, January 23, 2002

The above-entitled matter came on for technical conference, pursuant to notice, at 9:30 a.m., Alice M. Fernandez, presiding.

BEFORE COMMISSIONERS:

CHAIRMAN PAT WOOD, III

COMMISSIONER LINDA KEY BREATHITT

COMMISSIONER NORA MEAD BROWNELL

COMMISSIONER WILLIAM L. MASSEY

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ROBERTO PALIZA, Principal Consultant

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P R O C E E D I N G S

(9:30 a.m.)

MS. FERNANDEZ: Could I get your attention? I'd like to try to keep this close to schedule so if people would start getting to their seats so we could get started very soon.

(Pause.)

MS. FERNANDEZ: It looks like we have most people now. Good morning. Welcome to the second day of our conference. I think yesterday's was very productive and we learned an awful lot, and I'm sure we're going to learn an awful lot more today.

This morning, we're going to move to the western side of the country. We have panels this morning discussing the Northwest and Texas. Our first panel is representatives from RTO West who are going to discuss the long-term congestion management and some of the specific issues in the west. From that panel, we have Bud Krogh, Steve Walton, Preston Michie, Yakout Mansour and Shelly Richardson.

With that, I'm going to turn it over to Bud Krogh who I think is going to give a bit more of an introduction.

MR. KROGH: Thank you very much, Alice. Good morning to everybody. I'd like to thank you very much for including us in this educational workshop. I'd also like to thank the Commission and the Staff for the many activities they've engaged in to learn more about the West and the Northwest and particular the conference the Commissioner sponsored last November in Seattle I thought was very helpful for those of us in the West to explain some of the unique features of our energy market. We thank you for that and look forward to further dialogue with all of you.

I'd like to give you a little short background on those on the panel this morning. First, to my immediate right is Steve Walton who has a very extensive background in transmission. He's an electrical engineer with experience at Utah Power and Light, Pacific Corp and a former trading company in Houston.

(Laughter.)

MR. KROGH: He has joined RTO West as of January 2nd. When the Seattle Mariners sent Alex Rodriquez to Texas a couple of years ago, we thought we were never going to get a fair exchange, but with Steve Walton being sent to the Northwest, it's more than made up for it, and we've got a very good deal. It's great to have Steve with us. Steve's going to give you the main briefing on the nature of the Northwest primarily hydro system and what this means for market design. He will also sketch out the elements of the proposed RTO West Congestion Management Model which I hasten to say is a work in progress as are other elements of our market design that we will be submitting to you shortly.

To my left is Yakout Mansour, a Vice President of Grid Operations and Inter Utility Affairs for BC Hydro. Yakout has been a very active participant in the development of RTO West from the very beginning, first as the Canadian participant in our regional representatives group, and most recently as the BC Representative on the Filing Utilities Group. Yakout's been very active right from the start.

To Steve's immediate right is Preston Michie. He's a former senior counsel of Bonneville Power Administration and for the past year has been a senior consultant to Bonneville on the RTO West Development.

To Preston's right is Shelly Richardson, counsel to the Northwest Requirements Utilities, the NRU. Shelly, like Steve, Yakout, and Preston, is a very active participant in all the activities in developing RTO West. I would sort of call these folks the special forces in putting together RTO West. They've worked very hard together over the past two years. As I mentioned, the RTO West Stage Two filing is scheduled to be coming to you shortly. It is scheduled to be submitted on March 1. It will contain the components of RTO West's market design, congestion management pricing, planning, and market monitoring, a proposed transmission operating agreement, some revised by-laws that you asked us to revise in the last filing that we submitted in October of 2000, a liability proposal. Stage one was submitted on October 23rd, 2000. And you approved our governance structure and our scope on April 26th, 2001. What we are submitting to you on March 1 will build upon that earlier set of filing documents.

As many of you know, we at RTO West have developed our market design proposals through an extensive, collaborative process. Most of the key stakeholders in our region and throughout the west have been involved in technical work groups and in participating on the regional representatives group, so it's been a very active, very open process right from the start.

While we seek consensus on all elements of our market design among the RTO West filing utilities and our stakeholders, every now and then on occasion we fall short of complete unanimity on every element every now and then. This morning, after Steve's presentation on the nature of the Northwest Hydro System, Yakout will offer his views and those of some marketers on a few elements of our market design and Shelly Richardson will offer her views that reflect some of the strong interests of public power on those same elements of market design.

Our hope is that the market design NOPR will be sufficiently flexible to accommodate our region's unique features. Yesterday we heard from a number of the speakers that flexibility was the hallmark to their market design activities. We hope there is sufficient flexibility in your NOPR so that what we propose can be accommodated therein.

Again, I'd like to thank you again. Mr. Chairman, before you came, I thanked you all for coming out to the Northwest in November. You heard it? Great. We appreciate that and we look forward to further dialogue.

I'd like to turn it over to Steve Walton now who will make our major presentation.

Steve?

MR. WALTON: Thanks, Bud. What I'm going to do today, there are a set of slides here we're going to run through. In the process of that if there are questions that come up, if you'd just address them like we did yesterday, I'd appreciate that. It's easier to try and get them in the flow of things than it is to try and come back.

In the printed materials, there are three graphics at the back. When we go to there, I'll refer back and forth. I'll just interleave that, just so you realize where the graphics are. There's three at the back. When I was a little boy and I would be reading a book late a night, if it got too frightening, I would turn to the back page and make sure the hero survived, and then go back to reading it. It removed the suspense but it certainly lowered my stress. So the first thing is we're going to go to slide 9 at the back and give you the punch line, and come back and tell you how we got to that.

(Slide.)

Just so that you know where we're headed, where we've come with this congestion management process. We've come a considerable distance in the last few months. Beginning in about September, we have been working extensively on a flowgate physical rights model. As a result of a number of difficulties we encountered in September, we made a shift to an injection withdrawal model which, in essence, what it comes down to is a nodal locational pricing with nodal prices and a day-ahead scheduling process that deals with congestion clearing. A real time energy balancing market, a unit commitment process that's based on balanced schedules and a voluntary process and transmission rights that are financial and in effect are what you would call point-to-point, although I would more technically call them points-to-points because it's sets of injection and sets of withdrawal points. We'll come back to that later in a little more detail, but I want you to be aware that we had in fact made a substantial shift in the last few months from what you may have been aware of when you were following things along.

Let's go then back in the paper to the overview. The major discussion we'd like to have then this morning is to talk about the regional characteristics, in particular the nature of hydro operations in the Pacific Northwest and to talk about hydro-thermal coordination that occurs in that process through a set of bilateral contracts. Having done that, we'll talk about the implications.

(Slide.)

What we'll talk about then is the implications that those things have on the market model, particularly on two areas, the unit commitment process and the implications that that has, and then on the definition of transmission rights and how we use those.

(Slide.)

Turning to slide number 3, I'd like to give you an outline, a view of what the system looks like. In passing, I should mention also that the eight utilities that are now the filing utilities intend to consolidate their control areas into a single control area when RTO West begins operation. So there is a single control area for those groups. There will be residual control areas or other control areas from parties who don't join, but all the parties joining will form a single control area.

One of the distinguishing features of the Northwest is shown in this chart here, and that is what I would call the inventory of resources. What's available in most areas, especially thermally dominated areas, you have a set of baseload plants and you have a set of intermediate plants and a set of peaking plants on top. The general operating regime is to run the baseload plants flat out, to move the intermediate plants on and off during the week, and then the peaking units to meet the very top. If you look down through this chart, you'll notice that both in capacity and energy that hydro -- and let's talk about the energy here -- hydro makes up 60 percent of the energy supply, coal supplies about 33 percent. There is some addition in the other category which is only eight percent. There are some baseload plants, nuclear plants, and there is also the combined cycle plants in there. So when you come down to it, less than five percent of the capacity from the system is intermediate or what we call thermal peaking units. That's a very different mix of units than you will find in most parts of the country.

The hydro system therefore and the baseload system are operated in a different way. The system is energy constrained which means that it is short of energy. The hydro capacity, you look down through there and you'll see the peak load of the system, and this occurred in January of 2000, the highest peak load was approximately 56,000 megawatts. However, that represents something on the order of a 30 percent reserve margin so it's fairly generous there.

The problem is, if you'll look at the energy behind that, there's only so much water in a given year. So you can always put in an extra turbine and get more capacity but there's no more fuel for it. So you have an energy constrained system. The consequence of that is, you make that up or you supplement that with the energy coming from the baseload units, and if you'll look at the capacity factor of those baseload units, the average capacity factor is 85 percent. Individual units have as high as 91 percent capacity factors which means that the only time they come off is when they're forced off for an outage or when there's a maintenance outage. Those units are dialed up to full capacity and run flat out hour after hour after hour, so that all the shaping that's done in the system comes off the hydro system. This is a different operating regime than you typically see in other places. The unit commitment, as a result, has never been a major issue in the Northwest. The thermal units are essentially on all the time. The bulk of them, this big bulk of baseload units are essentially on all the time.

The peaking capacity or the flexibility, the peaking capacity of the hydro is such that if you have an error, you can bring it up in minutes. You can have a 750 megawatt unit at Coulee on line and at full output in ten minutes. The issue of unit commitment has never been an issue because you don't have the start times and wait times that you do with intermediate cycle units.

(Slide.)

I want to review with you some of the major hydro systems that we have in RTO West or will have in RTO West. The major systems are the Columbia River System, and we'll spend some more time talking about that. In the Columbia River System, storage is either in Canada or at or above Grand Coulee in the United States to include the Libby dam in the United States. All the storage is at the upper end of the river. In between on the down river plants, there is some what we call limited pondage, meaning you can move the level up slightly and down slightly but not very much. It's essentially run of river and they are listed as run of river although there's some limited movement of water pondage that can occur there.

The Peace River System also has an enormous amount of capacity. It is not a part of the Columbia System and it flows into the Arctic Ocean, so it has its own set of unique operating characteristics because of the Arctic environment.

The Snake River System feeds the Columbia River System but it is typically treated as a system. They're the lower Snake dams that are in Washington then the upper Snake above Hell's Canyon, the Hell's Canyon Oxbow and Brownlee complex of Idaho Power, and then on up the river. Those are the major systems.

(Slide.)

If you'll turn to the first graphic at the end of the printed packet, you'll find a diagram that shows the Columbia River System. The Columbia River System has approximately 54 million acre feet of storage. However, compared to other river systems that may have similar amounts of storage, such as the Colorado, the Colorado only has 12 million annual acre feet of water, the Columbia River System has a flow of 198 million acre feet of water, so it's a ten to one differential or more than that, close to a 15. Anyway, you get the picture.

(Laughter.)

MR. WALTON: I haven't been able to do the math in my head fast enough. I didn't write the number down, so anyway there's a substantial difference. So the flow volume on the Columbia in fact makes it unique among all river systems of storage compared to flow volume. That's what we're trying to manage is that flow volume.

(Slide.)

Going back to slide number 4 then, the river operations then become a critical matter as to how we operate the river. There is a diverse ownership along the river. There are BC Hydro has the northern end, the

Canadian System, there are public power entities that own facilities along there. The investor-owned companies have interests, financial interests, or contractual interests in the water, so all these have to be coordinated in some way between the parties in any hydro system like this. The up river storage creates benefits on the downstream side so you always have to figure out how you're going to share this along the way. If someone builds storage upstream and benefits other parties, they need to get some benefit for having provide that service. In order to do that in this multi-ownership system, and multi-nation system, a set of agreements have been put together that provide for this kind of coordination. The foundation one is the Columbia River treaty between the United States and Canada. That provides for storage and for sharing of production for the downstream benefits to come back to Canada in a certain way. Those are defined in that treaty.

In order to achieve that benefit and be able to return that benefit to Canada, and to provide those benefits and to maximize use of the entire system of dams along the river, the PNCA, the Pacific Northwest Coordination Agreement, was signed. It provides for this maximization of production on the main stem of the Columbia. Finally, that deals with annual production maximums and how you achieve that.

Then there are also even more detailed arrangements for hourly kinds of activities that are built into the mid-Columbia Coordination Agreement, so we have a series of contracts or agreements among the parties that allow them to optimize this use of the system and what the PNCA in effect does is treats this whole river system as if it were a single ownership and then divides the benefits among the parties.

(Slide.)

This chart here, this is graphic number 2 in your printed packets, and it shows a graphic that shows sort of sketch of the river system and where the storage occurs, and the distances. Along the bottom of this, you'll see the distance of these from downstream and, for instance, if you'll follow along and look up, there's 1200 miles from the Kootenay or Duncan Lake to the Astoria, which is the mouth of the Columbia on the Pacific Ocean. It shows the series of dams in between. You can see the amount of head in each one and their distance from sea level is marked there, the fall in the river and so on.

Another interesting thing is that you'll notice that the Canadian area is there so water, for instance, from Canada goes into the United States and it stored at Libby, goes down the Kootenay River and goes back into Canada into Kootenay Lake. Then it goes on from there back into Grand

Coulee back in the United States. So this international boundary, having drawn a straight line in whatever year it was, it didn't particularly follow water basins so it is an international optimization that takes place here. It also gives you some notion of the treaty base systems and so forth. The Snake River above Brownlee is not shown. It goes all the way back up into Wyoming where the Snake River begins.

(Slide.)

Going back then to slide number 6, let's talk about the optimization function. The typical optimization function used in thermal systems, as we talked about yesterday, is a fairly short-range time frame. The typical unit commitment process is either looking as much as a week in terms of trying to minimize start-up and so on and most of the RTOs now or ISOs that have been under operation that has come down to like a one-day unit commitment process. That was described yesterday in some detail.

The optimization function is to minimize cost. On this hydro system, there's a different optimization function. The objective function is to maximize annual firm energy production from coordinated operation of these hydro processes. When we say firm energy, what we mean by that is the ability to meet firm load. The greatest bulk of the water actually comes down the river in the spring and summer when there is peak load occurs in the Northwest in the winter when the river, the natural flow is actually at its lowest point. So in order to be able to provide firm energy or serve firm load, the jargon term is firm energy load carrying capability, in order to achieve that, we have to have storage in the system that basically moves that water flow from the summer period and stretches it across the fall and winter months so we can flatten out the flow on the river. So the optimization function then is subject to several constraints. One of those constraints is of course water availability.

MR. KELLY: Steve, question. I don't understand how the objective function would be different if you deleted the word "firm" and just maximized annual energy production.

MR. WALTON: If you can maximize maximum energy, you could actually produce maximum energy by simply having no storage and simply building as many dams as you could to maximize the use of the head as you went down the river, in other words the elevation drop.

On the other hand, if you want to serve loads in October, November, December, you can't do that because you can't serve those loads, so we are maximizing firm energy; in other words, we're maximizing the ability to produce energy at the time that we need it.

MR. MICHIE: We will draw a distinction between energy that on a contractual basis is not going to be available every year. We call that non-firm. It's really the energy that could be produced from the system in excess of firm power. So we adopted a conservative operating strategy. We asked ourselves if we experience a series of very low water flow in the system called critical water, how much firm energy can we produce out of the system. When we get a wet year, energy that can be produced from the system on top of that is considered non-firm. We generally market it and displace thermal resources. We make economic use of it. But when we're trying to serve Shelly's customers, we make a more conservative assumption that we're going to see low flows year after year after year. And of course three out of four years, the reservoir is filled but on occasion we do get very low water flows for several years in a row and we take that into account in calculating firm energy.

MR. WALTON: This is an important point. What's happening is you may be holding water back or holding back through the summer water, even though the price of energy might be quite high, you may still be holding it because you can't serve firm load later in the year unless you do that, so that's an important point.

MR. MEAD: Can I follow up on this? When you say that you're maximizing annual firm energy and not maximizing economic benefits or whatever, may I infer that those objectives are in conflict and that in some way you are not maximizing the economic benefits of the hydro power?

MR. WALTON: Preston, you can chime in on this also, but it's potentially possible that given the commitments that you've made to the people who have rights to this reservoir, to these resources, that you committed when you're going to provide that energy to them, and you're going to meet their requirements, it's conceivable that if the price were high enough, say in the spring time, that somehow you could make more firm but the objective function here is to service the load. We think that over the long haul that in fact provides the maximum economic benefit but it's a long-term view, it is not an hourly view. The reason for making the point that it's an annual optimization is that when it's gone, it's gone. Once one cubic foot of water goes over the top of the dam and you drop a pound of water over one of these dams, it does not come back. There's no way to get it back.

We in effect on paper move the water around because we substitute other energy and do returns and so on, but in reality it's gone, so it's a one-time opportunity for that year. So that's why there's an annual focus.

Preston?

MR. MICHIE: I would say the answer is no. This was going to produce tremendous economic benefits. But as

Steve is saying, it's over a longer period. There's a concept called a critical water period which is, let's assume the reservoirs, at the beginning of the water year, which I believe is October 1st, all the reservoirs are full and the Columbia's flowing from Canada around the table here over to Bonneville Dam. What I've done is, everybody in the system has filled their pool up to the maximum elevation, so we just store the maximum we can, and I now get a series of very low flows over, in our case, four years, which occurred in 1928 to 1932. Eventually, we're going to draft all that storage. The question is, when are we going to run out of water and can't produce any more energy out of the system. It's 42-and-a-half months, but the odds are pretty good because three out of four years, we're going to refill those reservoirs. So the effect of that is we're displacing not only fuel -- in other words, we don't have to have natural gas or coal as an alternative fuel or the capital investment in peaking resources to stand ready to serve those loads. We define firm energy in a very conservative way. I don't remember the statistic, but it's something like one day out 20 years, we will fail to serve load out of the system. That's the thinking.

So the economic benefit of doing the combined hydro-thermal operation in this manner is we're displacing not only fuel costs but the need to invest additional capital in the form of peaking units in one form or another. So if you didn't do this and operate in this way, you'd have higher capital and fuel costs. But it is a long-term in some respects, almost four year perspective, which is just a characteristic of our system. Other hydro systems might have different critical periods.

MR. KELLY: Can I test my understanding by saying it back to you a different way and tell me if I got it right? If there were a single owner for the system, and it was interested in maximizing profits, it would sell the most energy it could, whether in the northwest or the southwest when it was available. When it ran out of water, the northwest customers would have to buy from the southwest and overall you'd maximize profits for the owners, but you wouldn't minimize the cost to the customers in the northwest. You're minimizing cost to customers in the northwest or, to state it another way, maximizing economic benefit to the customers in the northwest, so it's very much a northwest focus. Do I have it right?

MR. WALTON: I think that's right.

MR. MICHIE: I would say that's true for the firm energy concept but you have to recognize that non-firm has value, so non-firm energy that can be produced above firm energy is exported to California, thereby spreading the benefits to California because it's economic to displace higher cost resources there. The revenue that comes from that is used to offset the cost to the Northwest, so there's a little bit of yes it is a Northwest focus but there are substantial benefits that accrue to our neighboring systems, particularly California.

MR. KELLY: I recognize that. I was just saying if we had a market model that assumed that generating owners were profit maximizing --

MR. WALTON: We'd operate the river differently, yes. But we're not, we're maximizing benefit to the participants in these projects.

MR. MICHIE: Just a little bit of push back on that. Even if you were maximizing profits, if your different investor owned utilities which do have an economic interest in plants in the mid-Columbia in this area, so you have federal projects here, federal projects there, they just can't operate freely for their own maximum use because they're going to run out of water, or they're going to cause impacts on other neighbors so it's more constrained because you have to coordinate, and the principles I was talking about are going to constrain the operations of profit maximizers in similar ways. Ownership does have some impact but not as much, Kevin, as you may be suggesting.

MR. O'NEILL: Can I try to clear this up? Are the firm's actual entitlement tradeable? In other words, you say you have firm, you're trying to meet firm energy requirements so you must have an idea of what those requirements are. Can they translate into entitlement and can the people with the entitlement trade them because if they can, there's no difference between that and a competitive equilibrium.

MR. MICHIE: The way you asked the question, it's kind of hard for me to think of it. Let's say that Alice is operating a project and water's coming down and she elects to raise the level of water in the reservoir to make her project more efficient. Your flow goes down. The coordination agreement allows Alice to do that but she has to compensate you with energy, so despite Alice's operational effect, she supplies you with energy from whatever resource she has available to use so that you're in the same position. Once you have that energy, you're free to sell it any way you like so that trading takes place really in the energy production after we account for these coordinations.

So I think in effect the trades take place as energy that you can sell but we don't necessarily trade the rights between you and Alice.

MR. O'NEILL: Under those conditions, you may not have a problem with economic efficiency.

MR. WALTON: The point here, the reason we brought this point up, is one of the constraints is that the units are not independent. What happens on this end of the river and what happens at that end of the river and everything in between, all of it matters. Once you drop a wall of water, and they release it at Coulee, it's got to be accounted for. Within a couple of days, it's going to come past Bonneville dam. There isn't enough storage in between to move it. They can move it a little bit up and down from hour to hour but it's got to come through. In order for everybody to get the maximum benefit, you do have to have a centralized operation. This has been done through these three agreements that we described, but there is a linkage between them and that's important to understand. None of these can move independently. When someone bids a price, they have some limited latitude to do that. Because of the trading of energy back and forth that Preston described, there is a substantial amount of trade in that energy but there are those limitations on operation.

There are another set of constraints as well that limit the use of the system and that sometimes lead to what people would think were odd outcomes. From an economic point of view, irrigation, navigation, fish requirements, the list is there in the slide, all those things then bear on the ability to move things. So, for instance, if Bonneville has a barge stuck on a sandbar, they may be asked to increase the flow to float it, even though that may not be economic. They may have to drop spill water in order to move fish down the river when it may not be the most economical time to generate. So if you were just profit maximizing, you wouldn't have to do all of those things. But these are constraints then that are imposed on the operation of this resource.

The result is that incremental cost in this system is really based on opportunity costs. In other words, it's the question of what future economic value you're giving up when you release water at a given time. If I release it now, should I instead have used more thermal resources brought in an import from the southwest and used that water later on in the year. How do you get that benefit? That will have an impact on bidding.

(Slide.)

Historically, in order to achieve hydro-thermal coordination -- I'm going to go back and talk a little bit about how we integrate these thermal units. As I indicated, we have something on the order of 33 percent of the baseload energy comes from these thermal resources, so how do we integrate that in there. Historically what we do is we have a very active bilateral market, what we call a forward market, that was used to achieve this hydro-thermal coordination. In order to bring that into and centralize it, it's a very complex process. It is not a linear programming kind of solution because you have these long outliers. In fact, it's much more complex. Instead of doing that, what happened was we used the forward market and the bilateral contracts for the parties as the surrogate, and it was achieved through that bilateral set of contracts.

In effect, what happens then is the way the river and the thermal resources operate is the thermal units tend to run flat out, Colstrip and Bridger, the thermal units in Utah, they run flat out up to maximum capacity. The peaking and shaping in the Greater Northwest Power Pool comes in out of the hydro system. We have called that here idealized pump storage. Let me give you an idea how that takes place.

In the eastern end of the system, these units are dialed up to full capacity. It's 2:00 o'clock in the morning and load is low. That means there is surplus energy being generated. That surplus energy is being sent to the Northwest to meet their loads. When those loads are being met then, the wicket gates are being closed, shut down, so there's less water going through those dams, there's less power being generated, and the balance is being met, so the energy is being moved from the thermal plants to the hydro areas into the Oregon Washington area to meet the load.

Now load comes up during the day. As load comes up during the day, the peaking then comes up on the hydro system and the water begins to flow in the hydro system. On the east side what it looks like is the load is going up and it's basically eating up or using up the capacity of those thermal units. This means that you're drafting more from those reservoirs during the peak hours than you want to draft for the whole day. Then as the load drops back down again at night, this energy is returned. This exchange and return policy done through bilateral contracts has been the way that we've optimized this hydro-thermal system so that those baseload units are in fact dialed up to maximum but energy is returned.

When I was working for PacifiCorp, we had a contract with Bonneville and it required 168 hour return, which is one week, so the energy had to be returned in a week. The reason for that was you couldn't return it all during the weekdays but you had the weekends when you had those baseload units still running at maximum capacity recharging the system. It would be as if you had a small generator feeding a big storage battery and you took all the peaks out of the storage battery, but the charger had to have a full week to recharge the battery.

So that's kind of the way this works. You can look at the flows on the Colstrip system, on the Bridger system, and you'll see the same impact. This day-to-night cycling that goes back and forth.

(Slide.)

MR. WALTON: In fact, going to the last graphic, graphic number 3, you'll see this is actually the flows on the D.C. intertie into California. The reason I picked this one out, I think it's quite interesting. If you count the little peaks that are in there, it happens to be the month of June and you find 30. That turns out to be of course the daily peaks, so that what's happening then is you have day-to-night exchanges.

If you look on this chart, you'll notice, this is in June of 2000, this is a month when things were pretty bad. But you'll notice, partway along, you'll see along there that as much as 1,500 megawatts was being exported from California to the Northwest in off-peak hours. Now they're returning, they're sending back 2,500 megawatts on peak in some hours. But this day-to-night exchange was taking place with a hydro system even outside the Northwest with California.

So that's that pattern on the usage of this resource back and forth. It affects the entire West. And in fact, the reason I believe that we have the trading hubs at MidC and at COB, those were originally developed to enable this bilateral trade that enables us to do this hydro-thermal coordination. Even the Palo Verde and Four Corners hubs are involved in this trade as well. Back in my days at Utah Power when I was a planning engineer, one of our major jobs as planners was to figure out how much we could export into Arizona, which would be exported to the California market. And that was in 1975. So this Western market is of long standing. There's a lot of trade, but it's been that kind of activity.

(Slide.)

MR. WALTON: So, we then tried to sketch out for you, and we'll be happy to give you more details on that if you want more, but the needs then for the future, how does this impact the market model? What consequences does it have? Does it mean we can't use locational prices or we can't use nodal prices?

It does not mean that. What it does mean is that the nodal prices need to be based on voluntary, bid-based bids. That's not so different in some ways. It is in other ways, because the bidding structure or how people construct their bids and how that is interpreted may be different because of this optimization that we've talked about about this annual look at how they use the water.

The second thing is the unit commitment, the centralized unit commitment really wouldn't work here. If we used centralized unit commitment, what we'd have to do is we'd have to bring the entire operation into the RTO. You'd have to bring all those hydro operations into the RTO, and it would no longer now be just a transmission operator, it would be the operator of the energy system. You would no longer have separation between transmission and generation. And I don't think that serves the purpose we're out to do that. It means that the unit commitment process needs to be based on self-commitment, and we're working out the details of that.

It also probably is a one-part bid rather than a three-part bid. In a hydro system, startup doesn't mean anything, and minimum run on the thermal base load units, there are startup and minimum runs, but we don't have a run that way. We're maxed out, dialed up, pedal to the metal. So it really has not been an issue. So that's the reason what our proposal will have in it is a different approach to unit commitment.

The merit order then will be the merit of the bid order. The bids and offers are going to be linked together to some degree because of this coordination problem we talked about along the river, and they'll be based on opportunity costs.

Finally, another requirement that we need is we have this active forward bilateral market that allows this hydro-thermal coordination. As a result of that, we really don't want to destroy that in the process of creating a real time or a day ahead market. So the two have to converge. We want to be sure that they dovetail and we don't destroy what we already have in the process of creating an improvement and going forward.

MS. FERNANDEZ: Can I ask a couple of questions? In terms of your first bullet that the nodal prices must be based on voluntary, bid-based prices, is the basic point you're trying to make there that the bid prices have to reflect opportunity costs?

MR. WALTON: That's one of the points, yes.

MS. FERNANDEZ: So that any type of bidding system where it's based on some sort of measure of marginal cost, whether it's looking at it just in terms of, I guess in the strict term, not considering opportunity costs would be a problem.

MR. WALTON: Yes. To the extent, like traditional things, they look at the incremental fuel cost and losses as the incremental cost to the system or the marginal cost. That creates a problem here because there is no incremental cost. The drop in the water has a long-term interest, which means that it's the value of that water in October, November, December that we have to consider in June when we decide to release it.

MR. O'NEILL: Steve, could I just clarify? I don't disagree with anything you just said, and even in the eastern unit commitment models, they allow self-scheduling. So that even if you would have had a full-blown unit commitment model, all of the hydro resources would be able to schedule themselves in without penalty. That's part of the market design.

MR. WALTON: I guess another way of saying this is that the expense of a centralized unit commitment would be wasted in our area. We don't even need it.

MR. O'NEILL: I understand that. But we need to make it very clear that self-scheduling is a part of the market design.

MR. WALTON: What I'm trying to also emphasize is that the degree of self-scheduling here would be completely different. It would not be the exception to the rule. It is the rule.

MS. FERNANDEZ: Then in terms of when you're talking about the three-part bids, the way they're set up it's an option. You don't have to use them. You can submit a one-part bid if you want, or you can submit three parts. Your point is that it really isn't necessary?

MR. WALTON: It isn't necessary. If you were required to submit a three-part bid, how do you submit a three-part bid? If you put in a zero price for the hydro unit, then the algorithm says, well, then, run it. You say, no, no, no. I don't want to run it this day, you see. So it doesn't even have meaning in the system here.

Our preference, our approach then would be to just have a single part bid which says I'll provide this much energy at that hour for this price but not to have the no-load and startup. There really isn't a need for it to begin with. And if we were to try to impose it on it, it would actually complicate the process.

MS. FERNANDEZ: Would it be a problem if it was an option?

MR. WALTON: We'd have to figure out how to outfox it. If you're a hydro operator, you'd have to figure out how to get around it. Rather than put that bug in the system, why not leave it out at the outset?

MR. O'NEILL: You can simply schedule your resources. The unit commitment system stands there for people who want to use it. If you don't use it, and I wouldn't imagine either the hydro units, like you said, or the coal units, or the nuclear units using that system. It would be used for gas units that can be fast started. It may not be an issue in RTO West at this point in time. It is an issue in other places in the West. Whether or not that has an impact on RTO West and how RTO West dispatches their resources, because you do do a lot of trading with California, in California, unit commitment is an important issue.

MR. WALTON: Because California has a different resource mix. In fact, we do have some distinctions about how we will go about things. That is a regional difference.

MR. MICHIE: One other sensitivity here is, we wouldn't want the market structure to cause the thermal units to operate differently than at least the baseload units. But subject to those kinds of constraints, I'm agreeing with Steve.

MR. WALTON: When we bring you a proposal in March, it won't have a centralized unit process. We're explaining why we don't need it. If the resource mix changed, that would be a different matter, but it's got a long way to go to overcome the 60 percent hydro, 33 percent baseload. It takes an awful lot of peaking units to make any dent in that.

So what we're trying to do is say as you design, as you write the market model, just be conscious of the fact what our needs are, and as to whether or not we really need that. If the function says you have to have a unit commitment process and the unit commitment process must assure that day ahead you are sure that you can meet load the next day, fine.

We can work that out with the process of the balanced schedules come in, we check them to make sure they're right. If there's a shortage between the forecast and what's really there, we can go out and call contracts from the hydro system and allow them to them make sure that we can meet the commitment the next day with the supplemental sort of process.

But the whole thing can be based on a voluntary process, and because we've an active hourly market, because we've always had a lot of energy trading that's been going on across the whole West for my whole career, then we're not particularly anxious about the fact that people want to generate to make money.

MR. O'NEILL: Let me just say, and I don't mean to upset the applecart here, but looking ahead a little bit, having disparate software designs in essentially the same interconnection or the same coordination area could raise problems later on.

One of the things you could do is take advantage of the general software design and simply not use the unit commitment until it became important. Because what we found in software development to date is once the software is developed and a change becomes necessary, it becomes a very difficult and expensive process.

MR. WALTON: Personally I always preferred to buy

Version 2.3 of anything.

(Laughter.)

MR. O'NEILL: Luckily, the Northeast folks have already gotten it.

MR. WALTON: The only point being that to the extent we need to make some modifications to fit, we know what they are. The reason for bringing this to you today was to try to describe what it is we do so that when you issue a NOPR, basically the pigeon hole is big enough for us to squeeze our entry into, the box is big enough, we can get it in.

MR. O'NEILL: I think as far as the Staff is concerned, we don't intend to try to reschedule your hydro resources.

(Laughter.)

MR. O'NEILL: You will schedule them, and the market will proceed and work around them, and traders will trade and trade around them.

MR. KELLY: Steve, just one follow-up. You started with statistics from the Northwest Power Pool. We segued a little bit now into RTO West discussions, which goes all the way down to Las Vegas.

MR. WALTON: Except for Nevada Power, the Northwest Power Pool includes everybody in RTO West. The greater northwest, I would call it, includes British

Columbia. For instance, on a transmission basis, British Columbia is about a third of the transmission, Bonneville is about a third of the transmission in the power pool, and the interior states, the investor-owned companies, are about a third.

Now in Bonneville's area on the Columbia, they have like 80 percent of the transmission. But the Colstrip Bridger Utah systems have been part of the Northwest Power Pool since 1941.

MR. KELLY: Would the market design meet the needs of generators in Nevada, customers in Nevada, if it's limited to just meet the needs that you've described?

MR. WALTON: The self-commitment process, because the bulk of the system runs off the self-commitment process, and for the scale of the system, yes, I think it can meet that requirement. They will self-commit and decide what they want to do.

Preston, do you want to add to that?

MR. MICHIE: I was just going to the same place. There are places where the effects of the hydro-thermal system we're talking about have less of an impact other than through prices perhaps. I'm just not familiar with Nevada units, but they may very well operate more like a traditional thermal system than we think of it.

But as you move closer under certain conditions, that might change. But as you move closer to the Northwest electrically as Steve has described, you'll see the impacts of hydro-thermal operation. Don't take that to the bank, Kevin, because I'm not absolutely sure.

MR. WALTON: Certainly all the way down into Utah, this day-night exchange I described is in fact how they meet the Utah load. It did when I was still there at PacifiCorp. So the only question is the impact on Nevada. So they're in the meetings. We're trying to work it out. They're in agreement with going in this direction, so I believe this meets their needs.

MS. FERNANDEZ: Can I ask you another question in terms of the ownership of the units? The thermal units. How many of those are owned by or what percentage are owned by vertically integrated utilities, and how many are sort of stand-alone merchant plants?

MR. WALTON: The baseload units, the major baseload unit complexes are at Colstrip, which is jointly owned by mostly investor-owned companies. The Bridger plant and the Wyoming generation of PacifiCorp and Idaho Power has part of the Bridger system. The Valley unit in Northern Nevada is a Sierra Pacific unit. But Idaho Power has an interest in the output.

The big thermal units in Utah were originally developed by Utah Power and not part of the PacifiCorp system, and in western Wyoming as well. By and large, the thermal systems have been vertically integrated companies, the exception being the Columbia River nuclear station. Is that it's name now?

MR. MICHIE: The Washington Public Power Supply System now known as Energy Northwest. We own the output for that project, so that's publicly owned. It's 1,000 megawatts.

MR. WALTON: In terms of new investor owned or merchant plants, there are some new gas plants in the Hermiston area that have been added. There's another one coming on in Kalispell. Incrementally, there are new combined cycle plants that are coming on that could be termed merchant plants, but it's a matter of the mix is growing slowly.

The last item is the first item we came to, which is the major features, then, of this system. To come back to what we're planning to propose, then, is a real time balancing market with nodal prices that we will use day ahead scheduling. And the current proposal is to use balanced schedules.

The parties putting in the proposal are designing it with the thought that the Board itself, the RTO Board, once it's up and running, will be able to make changes. In fact, there's a provision that there be a three-year review to make sure things are working, and to make an affirmative review at that point. But we're starting with balanced bilateral schedules and the day ahead, and then clearing congestion, any congestion it may have.

This is an accept all schedules, to use the phrase that we've used in the past, sort of system. So that anyone who wants to pay the cost of congestion can have a schedule in if they have rights or not. This is not a physical rights model. It does not provide people with blocking. As a result of that, the unit commitment we've talked about to some extent, then the transmission rights are financial in the sense that you don't have to have them to schedule.

The existing rights of the transmission owners are intended to be pooled into a catalogued set of rights. Because of the flexibility that occurs in the system, it's necessary for people to be able to make adjustments and changes during the day. When we tried to do this with discrete flowgates and discrete rights and break them up, we ran into substantial difficulty, because we really -- the way we get the most of the system is that we net everybody's uses.

And so the concept is basically the existing contract rights would be pooled so that the net of them would be what is supplied. Then out of that, then, supply that allows us to release a larger amount of new rights which would be called financial transmission options, or FTOs. These would be based. They provide for the same kind of coverage, which is to cover your congestion costs up to the total amount of the cost. If you want the additional value out of them, you would sell them in the secondary market.

The final point there is the existing contracts are all to be honored within this catalogued set of rights. So, for instance, Bonneville will have a catalogue of rights that it currently holds. That catalogue will be based on its needs to meet its contract obligations to Shelly's companies, the investor-owned companies, and to anyone else who holds an existing right.

The ancillary services market is still a work in progress, and we're still working on those details.

I believe that covers what we intended to cover as a group. If there are no other questions, we'll move onto others.

MR. MEAD: I have a couple of questions. First of all, with respect to the real time balancing market with nodal prices, are these market clearing prices? Does everybody who transacts in the balancing market at a particular location pay or receive the same price?

MR. WALTON: Yes, they're market clearing prices in that sense. We're also talking about hubs and zones to simplify this, and also to make it so that, for instance, traditional trading locations like MidC, there would be MidC hub so that you have energy exchanges and trades that take place there just like they're reported today in Energy Daily.

MR. MEAD: Would there by any difference for a generator or load that transacted in real time on instruction from the grid operator there's an imbalance of load?

MR. WALTON: I don't see any reason for that to be different.

MR. MEAD: So uninstructed and instructed transactions face the same --

MR. WALTON: There has been some discussion about penalties for coming in short. For instance, we have a balanced schedule, but in fact you've underscheduled your load and you've come up short, there could be penalties involved in that. But in terms of the details of that, I don't know that we've actually talked about the details. But in my mind, there's no reason to be paid a different amount.

To the extent we can make that market clearing price work for both, that's the best way to do it in my view.

MR. MICHIE: I think when you see the proposal, we won't necessarily have all of those details worked out to exactly how the mechanics of the real time market are going to work. It's not completely figured out, for example, whether you have to pay the suppliers, pay as bid or market clearing. On the other side of the equation, market clearing price to people who take from that market has got a good deal of support.

MR. WALTON: I suppose my answer was my view of that discussion.

MR. MEAD: It sounds like perhaps the issue of whether there is market clearing prices or not has not been fully resolved.

COMMISSIONER BREATHITT: Steve, I was watching on the closed circuit up in my office, and I had a question for you, so I ran downstairs.

(Laughter.)

MR. WALTON: It's nice to know you're loved, you know.

COMMISSIONER BREATHITT: You were talking about pooling. One of the concerns that I have is how you take care of entities that have -- that are transmission dependent or public power and other entities like that that are concerned about not being able -- losing their contracts. And the pooled arrangement that you talked about intrigued me, because there's a lot of public power in the Northwest.

Are you here speaking on behalf of RTO West and not the particular company?

MR. WALTON: No.

COMMISSIONER BREATHITT: So that is an arrangement that the members think they can live with?

MR. WALTON: This goes back to this cataloguing process. When we were trying to tear this all apart and do flowgates, and part of the reason we abandoned it is because having made the yeoman's effort, it wasn't working, and we went to this injection and withdrawal model, because that's what we could nail down long-term.

The problem we have is we have to have all these existing contracts. Bonneville has hundreds of them that we have to honor, and most of those, a lot of them are public power. So in order to honor them and still get the maximum value out of the system, what we're going to do is catalogue all those rights. Everybody has these rights. As we come in closer to the hour and we get the actual schedules and we're able to net them, then we can say, okay, this is surplus. Put it out to market and sell it out of this thing.

In terms of what rights we have in that catalogue, they're the rights of individuals, vertically integrated utilities, but they're also the rights that Bonneville, for instance, needs to honor its transmission contracts and its power contracts with. Public power customers and investor-owned companies, because some of the investor-owned companies are essentially transmission-dependent also.

The idea was, rather than to try to dismember this into discrete elements that have to approximate and not very well fit was to build this big catalogue, basically to take out of the one pool what you needed to meet the combined requirement of the existing contracts and then release the rest as FTOs.

COMMISSIONER BREATHITT: Would the contract rights in this pool convey for the life of the contract?

MR. WALTON: Yes.

MR. MICHIE: I'll just supplement that. From Bonneville's perspective, we have to honor those contracts. We have two objectives: Make sure the load is served, pursuant to those contracts, but also that there not be cost shifts. We think the current proposal accomplishes that. And the pooling concept is really designed for a particular hour to have the RTO identify what additional capacity is available to be sold that isn't necessary right now to serve those contracts.

But over time, as load fluctuates and you move to different seasonal and hydro conditions, we have to be able to accommodate those changes. We think we have a proposal that does that. But again, the primary purpose is serve those loads as we're obligated by statute and contract to do, with, I should say, minimal but essentially no cost shifts.

MR. KROGH: Commissioner Breathitt, I think it might be helpful, Shelly, to respond to that question as well. It's an important one.

MS. RICHARDSON: I have a detailed response, but I thought rather than launch into it now, if it would be appropriate to continue with the final questions on this.

It is good to hear Steve speaking on behalf of public power, but I did have some additional points to make in a moment.

MR. WALTON: I actually wasn't trying to speak for anyone.

(Laughter.)

MS. RICHARDSON: But you did it well.

MR. KROGH: I didn't knock my nameplate off to keep you quiet.

(Laughter.)

MR. MEAD: Have I cut off anything? I was wondering if someone could talk just a little bit more about the nature of the transmission rights. As I read the alternate proposals on the Web site, there seem to be some features that differed from the financial rights on the Eastern system, like they only had value if you used them to schedule. Could you talk about --

MR. WALTON: I'll give a brief answer, and I'll be happy to spend more time with you at the break or whenever. But the brief answer is, yes, the right is designed. Instead of a cash-producing revenue like the FTR or the TCC, which produces a stream of cash, this instead is a credit against your congestion expense. That congestion expense is a credit up to but no greater than the cost there.

So we allowed them to be fungible so that if you have congestion,you have a set here and they have this value and you use a different set of pinpoints, the full value will be applied as a credit against your congestion cost. If there is a surplus, those are to be released. The way the owner gets the release is to send them out to the market. We think this produces a secondary market and triggers it.

In my experience, people who have the financial right that produces simply a revenue stream tend to camp on it and not sell it. Because why sell it? It's going to produce cash tomorrow. But that's a design feature that you picked up. It'll be described in much more detail in the filing, and I'll be happy to spend more time on it, but we had these other two parties who want to speak.

MS. FERNANDEZ: I think looking at the clock, we ought to move on.

MR. KROGH: I'd like to ask Yakout Mansour to speak next and then Shelly, if you could.

MR. MANSOUR: Thank you, Bud. With that elegant introduction by Steve, I hope by now you understand the significance of BC Hydro's participation in the RTO West process. A major partner in the river system, a major supplier, and being 95 percent hydro-based in dry water years, we depend on the market to serve our load. So our position's always been balanced by those of load serving entities. Those marketing, those that are operating rivers, and at the same time a utility that is trying to depend in the future on merchant generators. You can also see that with a significant role like this, and being a Canadian or an international entity, it would have been probably politically and procedurally easier to try to coordinate at the seams but it wouldn't be right; it would be easier but not right. So we've been heavily involved in the RTO process. We are a proud member utility of RTO West. We are a principal member of RTO West.

Our support to the FERC RTO initiative is still very strong and proactive. We believe in the global order and we believe in what it can achieve. As you may recall, in the October 2000 filing of RTO West, and the attachment of how British Columbia can be included in RTO West, this is an innovative way of including the BC market and the RTO West market while protecting all regulatory and political entities in both countries, so we are proud of that model and wish to support it. It was not easy but we worked with the principal stakeholders and the funding entities of RTO West. It's not easy to see that complication with federal and public power and all of those conflicting interests. Believe it or not, they even invited the Canadians to be part of it, to increase the complexity of it, but it was right.

That said, and after working through some critical issues of how BC can be included in RTO West, our issues right now are the remarks I want to make have nothing to do with the Canadian flag, they are pure market design issues that I want to add to what Steve has added but not on behalf of all RTO West but on behalf of BC Hydro. And I know that their views are shared by some market participants. I also want to really emphasize that BC Hydro, for one, was very pleased with the vision and concepts articulated in the FERC Staff paper of December 17th. When we read that paper, I don't know if you had a fly on the wall or what, but it really hit just about every hot button that RTO West has been debating. Some of those have been resolved to satisfactory transitional state at least, and I would say that that's the majority. But some remain unresolved, not necessarily will not be resolved but at least we haven't, and when you see something is getting to almost a dead end like this, I would say maybe standardization or some clear guidance is wanted at this point of time on these particular issues.

You have heard over and over again that the West is different. I'm sure you've heard it from other regions too that they also are different, and yes the West is different. But it is very crucial to understand really the limited extent of those differences and the limited exceptions to only what is warranted for exceptions. The limited difference in part should not lead to being different on the whole.

In the interest of time, I'll limit my remarks to only three elements of market design; namely, pricing, congestion management, and western market seams, and I will not repeat or reiterate any of what Steve elegantly articulated to you. And while I'm expressing those views, I do understand other views, and I respect them very highly too.

On pricing, the gap between the two main position among the RTO West stakeholders is wide on one main issue that I believe is fundamental to achieving an efficient and fair market. Eliminating of rate pancaking, which is one of the fundamentals of rate design, at least in what RTO is calling for is received by many as a form of denying the native load customers the opportunity to extract a contribution to the embedded cost of transmission in the absence of congestion. That sometimes is referred to as cost shifting.

I don't know if I can really comprehend it totally as cost shifting, but let us say it is. But we have two conflicting things. If we want to eliminate rate pancaking, it would be to eliminate cost in a way that would make things more efficient. Alternative structures are being proposed now which discriminate between new and old users, or existing users by a surcharge on new transmission users, which amounts to as high as 20 percent of the average energy price in the region. That simply will discourage any newcomer from coming to the market, if they are going to face up front some charge like this just for that part of the market participants. In competing with historical existing utilities i the region, I believe it's really necessary to develop a clear making standard and guideline in this regard because it has been a very hot issue in the West.

I want to switch to congestion management and you heard Steve Walton articulating elegantly how really what I refer to as LMP, even though we in the Northwest, we kind of don't call it LMP but it is an LMP and as a hydro-intensive resource-based utility. We supported the concept and others did too, but the early opposition to the concept in the region that you might have heard about a long time ago, in my opinion, was caused by I would say a mistake made in various literatures. In referring to the PJM model generically rather than LMP. PJM is a successful and leading application of LMP for what suits PJM interconnection, but LMP is used a couple of other places in their own ways. Whether we would call it fish LMP to protect fish, or wet LMP to account for the opportunity cost of water, LMP is applicable.

And you heard Steve articulating to you what the exceptions should be. However, I want to make also the following remark for your consideration. We believe that financial transmission options, rather than obligations, in a hydro-based system is more suitable, and two of the colleagues who made presentations yesterday kind of explained the obligation versus option when it comes to the possibility of congestion in the reverse direction to the rights and what it represents reliability.

For a hydro-system, we are really flow reversed between storage and generation a few times in large quantities within a few hours. That's a very high liability, and that's why we prefer options. But as you all know, whether they are options or obligations, these are hedging mechanisms that are very essential to exist in a model like this.

Now if there isn't enough conversion of existing rights to the new RTO tariff rights, that market will not be liquid and that mechanism may not work well. In this regard, the Staff paper elegantly addressed that issue, and it needs to be addressed, and asked three questions. How should this be implemented, over what time frame, and how should fairness to existing contract holders be taken into account. I would say I'm a really strong supporter of trying to convert those contracts to standard RTO tariff, it doesn't mean that the rights are lost. They just convert to the new RTO tariff as soon as possible.

I realize that there will have to be transitional process. I realize there will have to be a transitional process within a reasonable period of time. As a start, I suggest relying on incentive mechanisms but it must have the carrot and the stick philosophy. Financial incentives to convert to RTO service is one thing. But if it is not countered by limiting the ability of the rights holders who do not convert not to reassign or trade otherwise, it may not work either.

The time frame issue really of transition is not just limited to the conversion issue, but just about to all other issues. Some are proposing ten years and some are proposing 15 years and some are proposing 2011 and 2015. Mind you by that time, I don't have much to worry about. But really, as a matter of just fact, if that's the case, if we're talking about the year 2015, the western system demand is likely to grow by about 40,000 megawatts. If you want to encourage new investors and suppliers of new resources, new technologies, and to meet that demand promptly, the transition must be achieved gradually and leave time until that date for the right players, the right competition to happen. We can't make the transition that long.

The third issue is related to seams and interregional coordination and right from day one, you will recall that BC Hydro has been concerned about allowing multiple RTOs with different tariffs, business practices, and market structures to exist in the same natural market. That has been a concern right from day one. We caved on the institutional consolidation IT. I guess a number of us caved on it, because of whatever reason it is.

But we remain deeply concerned about allowing seams through differences to exist in the same natural market. We can't hope for coordination of seams. I don't know if that would mean anything, how seams are coordinated to permit them to create a seamless market. I don't know what that means even. Seams are seams. And if they exist, you don't have one market, the same natural market. Trades take place from BC all the way to California and east to west. What is that called. I'm trying to even get someone to explain it to me.

We believe at the least that the multiple RTOs of the West adopt common standards, practices on the key functions of tariff design practices, congestion management, market monitoring and interregional planning.

And how? I would suggest that is through a forum created by the RTOs themselves, rather than another independent entity from the RTOs. It's really our view that the strong umbrella organization like CIGWE that we are trying to promote in the west created by the multiple RTOs that enforces and maintains one seamless market is as necessary as the creation of individual RTOs themselves.

We also believe that allowing fundamentally different tariffs and practices and transmission products markets in the same natural market will result in inefficiencies that are not necessarily less in impact than what we have today. If you look at what we have today, other than California, we really have everybody having more or less an 888-based tariff.

Now the difference in application using business practices is creating a nightmare. Imagine instead of that, you create a number of entities that have different tariffs, and different practices. The combinations and permutations of those rules are not more efficient than what we have today. That's a very crucial point.

And I would like to stop at this point and thank you.

MR. KROGH: Shelly?

MS. RICHARDSON: Thank you and good morning. Bad news and good news here. The bad news is I'm the last one between you and a break, but the good news is, with any luck, as I think King Henry VIII probably said to at least one of his wives, this will be short but memorable.

(Laughter.)

MS. RICHARDSON: The point of the conference, as I understand Ms. Fernandez and others have described it here is to go through some of the similarities in differences between the various electricity market designs. With that in mind, what I would like to do today is three things. First, give you some detail as to the appropriate market design within RTO West's geographic footprint. Secondly, describe for you what the business interests are of the players in that market. I'm not quite sure that I have the same appreciation of what the right players in that market, as perhaps some of my colleagues do, but I'll try and describe the business interests of those players within the markets now, and then finally try and identify for both you

Commissioners as well as Staff how we can best meet those business interests through what you're doing on the market design and vision.

Let me start first here and put some faces on the operational coordination that Preston and Steve have described. Namely appropriate market design within RTO West's geographic footprint. The faces that I'm here to talk about are the stakeholders in that market design. In particular, in the geographic footprint of RTO West, there are on the order of 160, 160 consumer owned electric utilities in that footprint. Idaho, Oregon, Washington, Utah, Western Montana and Wyoming, Northern Nevada and Colorado.

Now I will grant you that within that 160 consumer and electric utilities, there's quite a bit of diversity. We have on the one hand the City of Seattle. On the other hand, I suggest there are utilities who have total service drops smaller than those necessary to serve perhaps Bill Gates' house, so it's quite a broad range of entities that we're talking about.

I have the privilege of representing a group that's consisting of Northwest Requirements Utilities. These are a group of approximately 50 small and medium-sized transmission-dependent, full requirements power customers and partial requirements power customers of Bonneville. But the bulk of my comments, I'm going to try and address more broadly the issues common among the 160 plus utilities within this footprint and where there are specifics to Northwest requirements utilities, I'll identify them.

Among the 160, every one of them consider themselves to be transmission dependent. The majority have their generation resources located remote from their loads for a variety of reasons which I'll talk about in a moment. Each one of these entities has a long term, pre-existing contract for transmission to serve their native loads. By long-term, I mean bilateral agreements that range in length from 20 to 50 years for purposes of load service contracts with the Bonneville Power Administration as well as with WAPA. The minority of these electric utilities in the RTO West footprint, the consumer-owned electrics who actually own generation are in the vast minority.

As I mentioned, Bonneville Western Power Administration supplies power to most of these folks to meet their load service. This is critical when you take both the power supply piece and put it together with the transmission piece. As I mentioned, all of these utilities have long-term transmission service contracts. Over half of them need an additional right, if you will, in order to just bring basic power for load service to native loads into their utilities. And this is a situation described as a general transfer agreement where you use the utilities benefit from the main grids to wield their power up to a point to serve their loads, but then they have to transact business over the facility of the third party to reach their loads. These historic agreements were in lieu of redundant transmission construction, and the product of these agreements in effect are load pockets that end up potentially on the wrong side of existing potential constraints. This is just for loads service. This isn't wheeling through to Nordstrom's in San Diego. The basic profile here is a little bit different than perhaps you may see in other parts of the country. That's the profile.

Let me talk a little bit about my second point, the business interests of the entities I'm talking about within the RTO West footprint. I was pleased to be able to participate by sitting in the audience in RTO Week. One of the comments I took from RTO Week, before you all was I think well put by one of your regulators, and it had to do with first doing no harm as you go forward with RTO policy.

For purposes of public power in the Northwest and market design, what first doing no harm means to us, I believe, is preserving reliable and adequate transmission service to meet our local load obligations. We do that now. This isn't a change from the status quo. The other business interest we have is doing no harm by preserving stable and low cost prices for that service, and when I take those two business interests and put them in the context of the status quo, for service with Bonneville's ownership and others, we largely have a pretty reliable system at cost to meet our load service obligations. So the business interest is continue delivering that. If it's under a new mechanism, well, we'll deal with the new mechanism, but we need to do no harm first.

Where that takes me for purposes of again the business interests of these entities and what's going on in the west, the congestion management proposal that's been described here, and I think Commissioner Breathitt, you asked the question directly, how that serves the interest of consumer-owned utilities in the region. For purposes of Northwest's requirement utilities, this proposal does a better job than any of the prior proposals in the Northwest toward meeting our business interests because load-serving non-profit utilities have their transmission rights arising from contracts preserved. They are not forced into a financial market when their primary and overarching issue and principle is to serve their loads.

Market designs that fail to meet the principles of providing adequate reliable transmission service to loads at a stable price fail to meet our business interests, period. This congestion management proposal appears to be meeting our interests. Now, how can you all help? I'll try and be brief because I know we're running out of time.

There are things in your market design and standardization efforts that I think you can do that will help entities like the over 160 utilities I'm talking about. One of them I've just identified. It's a congestion management plan that's flexible. By that I mean, we've heard market design emphasis for the last two days, flexibility so that participants can enter the market as they will, rather than being goose-stepped into the market now when their principal interest isn't financial, it's service to load. By that voluntary conversion of preexisting contracts as opposed to mandatory conversion is the type of flexibility we're looking for. Voluntary participation in a market, not mandatory. I appreciate my colleagues reference to carrots and sticks. Carrots and sticks are fine up to a point. And again, if we can't meet the business interest of adequate and reliable service to loads, we've failed.

Third, with respect to rights to load, rights to service, nothing less than the status quo does no harm, and to impose a standard that's sufficiently inflexible to permit that isn't something that anyone in the public power community that I'm aware of can support.

Fourth, with respect to what you can do, we've heard some on the pricing model. The pricing model that's currently being proposed in the RTO West footprint collects from all users of the system, whether they're short or long-term, whether they are new, old, or indifferent, and does so, as best we can tell, without imposing additional cost shifts on players in that market.

I appreciate that one person's cost shift is another person's monopoly rent. But in this instance, it seems highly comparable to expect all users of the system to pay for that use.

And finally, with respect to the flexibility, a planning model is under development with RTO West that as a standard provides as best we can tell for reliable back-up in the event of reliability issues. That's key, especially where as I've described you have utilities who are at the end of the line basically, and frequently that line is owned by a competitor.

Now as far as standardization, three requests for your help there. The first is with respect to what facilities are appropriate for inclusion within an RTO. There's a fair amount of debate on that issue. My read of the guidance we've received from the Commission is fairly clear. If the facility is used and necessary for wholesale service, then it ought to be under the RTO's control for both pricing and planning purposes. That's a standardization step which Northwest requirements utilities would endorse, I believe.

Secondly, there are actions occurring now before the Commission which would if concluded prior to the formation of your market design standards, would have the effect of predetermining outcomes. And by that I mean quite specifically filings before you that would ask you to identify which are the appropriate facilities and which aren't for purposes of distinguishing between transmission and distribution. Acting on those filings in advance of developing your market standards, in advance of acting on RTOs that have been proposed before you, I submit would have the effect of predetermining the outcomes in that, and that's not a path I would recommend you take.

And finally, with respect to standardization, I think you've heard Bonneville identify, and many of us in public power and elsewhere, that for this system to work, the benefits need to be identifiable and need to be specific enough so that on a state-by-state basis, parties know that we've done no harm.

So with that as the backdrop, I hope you have a feel now for the entities, what their business interests are, and how both Staff and the Commission can work toward that as you're working through your market standards NOPR.

And I apologize for rattling on so quickly, but we're sort of short on time. Any questions you might have, I'd be delighted to take. Don't all rush at once.

CHAIRMAN WOOD: On the planning model, how does what you've got in RTO West sync up with what the WECC does or will do?

MR. KROGH: We understand, Mr. Chairman, WECC will be doing some coordination of planning among the RTOs, and CIGWE, the group that Yakout mentioned, is developing an interregional planning expansion work group which will work closely with the WECC. We just had our first meetings in the last couple of weeks. That follows up on the conference you held in November in Seattle.

We think we're going to have a good coordinating group within WECC that will be working closely with CIGWE, which will be doing the actual expansion planning for the region.

CHAIRMAN WOOD: Okay. Thank you.

COMMISSIONER BROWNELL: I have a question. Shelly, you can comment, but so may anyone else. I'm interested in this conversion process and a couple of specifics. What rights in fact will be available for conversion after the existing contracts have been handled? And how long do you anticipate -- and I suspect the answer is different from where you're sitting -- such a conversion should and could take and still support market development?

MS. RICHARDSON: In terms of the rights, the price that Steve Walton described of cataloguing preexisting contracts as well as load service obligations is intended to cover the scope of rights that each of these individual contracts include as well as the noncontractual load service obligations that some of the investor-owned utilities and others have.

All that said, we're understanding that in the process of cataloging out of that, an entity who has a transmission right will have the ability to in effect retain its contract, not convert, and receive through the catalogue rights what amounts to the same service it would have otherwise received for the duration of that contract.

If, on the other hand, an entity having identified this library of rights through the catalogue, then chooses to convert those rights into the financial options and create the market that is sought, they'll have that option. And as discussed, to date, I'm not aware that there is an RTO West recommendation of requiring conversion in advance of termination of that contract, nor would we support one, quite frankly.

MR. KROGH: Did you want to add to that, Preston?

MR. MICHIE: It's actually just a technical point. If you look at conversion as sort of a longer term perspective -- we covered this a little bit earlier -- the way we net out schedules, there's a diversity in load obligation. So you're freeing up -- ATC is probably a poor way to describe it, but available transmission that can support additional transactions. The trick is to know when the schedules are permanent or committed, which we think of as day ahead, although we have to allow for changes in hydro conditions between day ahead and real time.

But subject to those ideas, what we're trying to do is net out all the schedules and then make available as options, using Steve's term, whatever space is available on the system. The disadvantage, of course, it occurs in a shorter timeframe than some of the marketers and others might like. But where there's available transmission, the key concept is we're going to make it available subject to the constraints Shelly said of making sure load gets served.

MR. WALTON: The exact scope of the cataloguing process has not yet taken place. So some people think it's going to be minuscule really. Some other people say, no, there's going to be quite a bit released. But until we actually put all the numbers on a piece of paper, we're not going to have an answer to the question.

MR. MANSOUR: That's exactly the point. Cataloguing, it's really specifying your rights and the facilities that you are turning over to the RTO to maintain those rights, but it is not conversion to the RTO tariff. You're not converting those rights to the RTO tariff. So the RTO doesn't have any flexibility to do anything with those things unless the rightholder voluntarily converts to the RTO tariff.

So when you pool all of those catalogued rights and everyone keeping in mind that now they're going to work on all scenarios to make sure that the same rights are maintained under every possible condition, the expectation is you're probably going to have a highly subscribed system, oversubscribed or very little left. But this core remains whether anything would be left for others or not.

So as Steve correctly said, that's point number one. But the main point is, as far as the rights that are converted to RTO, that the RTO really offered them as a hedging mechanism for LMP to work. That is not required in the current proposal.

COMMISSIONER BREATHITT: Is what I'm hearing that you might have a fledgling LMP product for a period of time, correct?

MR. WALTON: The system will run as a locational pricing model, to the extent that the standard jargon LMP means what we've been talking about, yes. To the extent that it's fledgling, I don't really think it's fledgling in the sense that there will be prices for all the other points.

Now there is the balanced schedule factor, and what's the other issue? But the conversion of these rights when people have these catalogued rights, they'll actually be settling those. There'll be actually be a congestion cost calculated for everybody who has a catalogued right, and that catalogued right will work just the way the FTO does, which is a credit against that.

So in that sense, it really will be -- the CTR and the catalogued rights, excuse me, and the option rights, will settle the same way, so the same settlements will apply to both. So it's not like there's a set aside. We're not going to take these catalogued rights, pull them off the system and solve for the congestion costs as if that capacity wasn't there and create phantom congestion.

In fact, what will happen is, the whole system, the full ratings will be involved, and those who have catalogued rights who have congestion costs calculated for them will simply receive a credit equal to what they had if they had that set of options.

MR. MICHIE: I guess I would say the other key concept is that there is no inherent right answer to what the marginal cost of the hydro project is. So we don't think of marginal in terms of the discrete costs you might assign to a thermal project when it's coming up and then running and then running full tilt.

So the hydro system value might vary with conditions. If we're spilling water, which means we can't find load, it has very little value. Conversely, when it's available only to serve fish, it has high value or it won't be made available on the market. So the idea of a voluntary, bid-based system to accommodate for the difficulty of pricing hydro is sort of a key feature here too.

COMMISSIONER BREATHITT: Does anybody think that there might be some amount of voluntary conversion?

MR. MICHIE: Yes. We have contracts that are essentially point-to-point with little flexibility is the term, meaning I can move power one direction or another. There's an argument whether they will convert them automatically, but personally I think you're better off to do that the way we've structured the congestion management proposal, because you can convert and not do anything. You don't have to sell your FTOs, so you sort of get the benefits of doing nothing and have a choice, sort of a free choice.

But those are contracts which are path contracts, going from Point A to Point B. And I'm going to guess wrong a on the number, but a number of those contracts. There are a number of other contracts that have flexible injection and withdrawal plans where the conversion issue is more problematic because of the flexibility that's inherent in how those contracts are used, particularly when combined with hydro projects.

So the answer is yes. They're the classic contracts that probably should convert.

MR. MANSOUR: In other words, we don't know.

(Laughter.)

MR. MANSOUR: And this is the issue. Without knowing that you have liquid market for those hedging mechanisms that make the concept work, it's very difficult for anyone to convince you that, yeah, that would work. And now when you get to standardization, you get good standards as far as maybe the burden of proof on every application has to demonstrate in real terms, not just by thinking that people would wish to, that there will be a liquid market on those options or on those obligations.

MR. CANNON: Two questions. Is this cataloging of transmission rights sort of a one-time deal in terms of looking at the existing contractual rights, or is there the possibility that additional contracts can come into this catalogue in the future?

MR. MICHIE: I've got a couple of thoughts. I'll start with the proposal will require some updating. For example, as Shelly's customers' loads grow, our statutory and contractual obligation will grow with it. So we have to adjust the assets, so to speak, to supply those, which traditionally come in the form of transmission lines, but sometimes we redispatch power and we do other things to serve those loads.

So you have to keep track of those kinds of considerations. So we do anticipate some adjustment annually to account for that.

MS. RICHARDSON: But the distinction is the cataloguing process pertains only to preexisting contracts and current load service obligations. So if a new entrant, as I understand the current RTO West proposal, a new entrant or somebody seeking a new transmission contract comes into that market, they don't get subject to the cataloguing process. Rather, they go to the RTO for service. Because cataloguing, and correct me, guys, if I'm misspeaking, but cataloguing, again, takes account of what's on the books now, not the new stuff, if you will.

MR. CANNON: And the second part of that question. Steve, I think you mentioned that there was going to be or might be a three-year automatic take a hard look at how the tariff is working, how the market is working and sort of an affirmative obligation to make a filing every three years that's sort of under consideration.

MR. WALTON: Well, I will tell you what I read in the last version of the paper that is being drafted, and subject to the fact that they're redrafting it today again.

But the intention is that the RTO Board would be given the authority to make changes as they saw that they needed to make them. And beyond that, that at three years, not an interval, but just after the first three years, that they would have an affirmative obligation, an affirmative obligation to make a full study of this to see if it's working and then to make recommendations for changes, subject to not, again, unwinding values that people already have. So that's currently what's in the report.

MR. CANNON: That's sort of where I was going is could RTO West -- among the issues that they could look at in terms of how the market is working and whether it's working well, is one of the issues they'd be able to look at in the future, be it after three years or whatever, whether these catalogued transmission rights are or are not interfering with the efficient operation of the market?

MR. WALTON: I think that's an issue -- I suppose it's an issue they could look at. That issue hasn't specifically been talked about. But, for instance, even other details like the day ahead settlements or the hourly settlements and the details of how things are going there, the interface and the nature of the rights that are issued, and what are the options, and whether they're undercollecting and overcollecting. And, you know, the list goes on and on.

But I don't anticipate that the catalogue -- you can answer, Preston. You were in the negotiation of that. Maybe a better answer.

MR. MICHIE: Well, the concept here is to make sure we have enough transmission to support our contracts.

That's in simple terms what we're doing. So that's kind of a starting point. And the principle is to have everybody who signed contracts stand behind them with transmission assets or be on the hook to cover the costs that's a differential, should it exist, between your transmission system and the contractual obligations we have to folks like Shelly and her customers.

MR. WALTON: But at present, there is no -- in the present position there's no discussion of anything other than voluntary conversion. There is discussion about how to create incentives so that people have a reason to convert, but there is not a discussion of a mandatory conversion at this point in the paper as written.

MR. CANNON: It sounds like a creative way to try to deal with the whole issue of grandfathering, but I'm just -- it would give me some reassurance if there was sort an affirmative look-see at some point in time in the future to see whether indeed this is somehow interfering with the efficient operation of the market or whether indeed it's a good complement and a wonderful way to finesse the problem.

MS. RICHARDSON: And Sheldon, one of the things we haven't addressed directly is the governance of the proposed RTO West, which is by an independent board. And the look-see that Steve's describing would be performed by that board looking at the market for purposes of RTO West's geographic footprint to see what's working and what's not.

My expectation is that if any component of RTO West isn't performing, isn't providing a market that's well functioning, it's going to be examined by an independent board. That's the whole point of having them be independent.

So my hope is that whether it's your specific concern or others that I may have with respect to load service, that the independent board is going to be sufficiently independent to be able to make that kind of determination. We need to look at this, either fix it or not if it's a problem.

MR. MANSOUR: I have just a follow-on to what Shelly said, which I agree with. If you want to give the board flexibility to do something like this in two or three years, then we really have to then think what goes into the TOA versus what goes in tariff. If that's the case, yeah, we would support that. But anything that has a possibility of a change after transition, it better not be committed to in an agreement way that the board would have no way to deal with it and rather have it in the tariff. And that gets to the issue of what goes in that agreement versus what goes in the tariff, around the point that you just raised.

MR. O'NEILL: Can I sort of raise a point of optimism? I mean, this discussion -- I remember this discussion taking place almost a decade ago when we were thinking about unbundling natural gas. And there was this same feeling. As a matter of fact, there were conferences sponsored to make sure that when we unbundled, all of the transmission rights would be feasible.

And there was lots of anxiety, there was lots of worrying, and the Commission went out of its way to make sure that the existing rights were satisfied to the extent that they could, and I think we did a pretty good job, because I haven't heard many complaints.

And as soon as the market opened up and as soon as people were given the right incentives, there was excess capacity everywhere.

MS. FERNANDEZ: I think I may take Dick's positive note as a good place to break. Because I can see our audience is getting a little antsy. We've had a very long session. Thank you all very much. It's been very informative.

Since we're running a little late, can we get back together at 11:30?

(Recess.)

MS. FERNANDEZ: Could people start going back to their seats so we could restart?

(Pause.)

MS. FERNANDEZ: Our next speaker is Sam Jones, Chief Operating Officer of ERCOT who's going to discuss experience in the market design that's currently in effect within Texas. With that, I'll turn it over to Mr. Jones.

MR. JONES: Thank you very much. It's a pleasure for us to be here today and talk to the Commission Staff and to the group. I'd like to start out by saying I know a little bit about a lot of what we do, but I don't know a lot about little bits of what we do, so there are some questions I may have to defer. Some of our stakeholders are here and can answer some of those.

Our process is basically a stakeholder driven process, and our whole model was put together by our stakeholders and some of the folks here were experts in that operation. Basically what is ERCOT? We've been a wholesale overseeing wholesale competition in the ERCOT region since late 1996, so we've been an ISO and in the wholesale competitive business now for over five years. We are currently a single control area intrastate interconnect. We're not synchronously connected across state lines. We're Public Utility Commission of Texas jurisdictional. We currently oversee about 70,000 megawatts of generation in the ERCOT region. From that, we serve peak load established two years ago of 57,600. So currently we enjoy a good reserve margin of generation in our region. We oversee about 37,000 miles of transmission lines. We are governed by a stakeholder board with representatives from all sectors including the customers. We actually have consumer reps, the Office of Public Utility Council for Texas, residential, the small commercial and industrial. They actually have more votes than anyone else. They have a vote-and-a-half each on the board.

I know there's some discussion obviously in regions over independent or stakeholder boards. Even within our region, there's some feelings both ways. I will have to say that our board has met regularly during our current retail startup phase, and has been a very knowledgeable board. They've worked hard, they've made a lot of good decisions, and have worked well with us. They're very knowledgeable on the issues.

Finally, the ERCOT staff and the operating function is a totally independent third party not-for-profit organization, so we have no financial interest in the market at all other than just seeing that it operates the way our stakeholders would like it to work.

(Slide.)

Just to talk a little bit about our basic wholesale and retail market, I realize retail is not the focus of this conference, but ours is wholly integrated so from time to time I will mention the retail end of it. How does it work? Basically, ERCOT became a single control area last summer for wholesale operations, and I'll talk a little bit more about that in a minute. Within that framework, the competitive retailers sell to the eligible retail customers. Not all the customers are in an eligible area. The state law that created or resulted in our current market specifically said that municipals and coops, which were about 20 percent of the load in ERCOT, did not have to opt into retail competition, but even if they don't, they are still retail providers to their customers and they must participate in the overall wholesale market, so they are very much a player in our wholesale activities.

Within the competitive areas, all retailers schedule through what we call a qualified scheduling entity. Basically, the competitive retailer is an entity that is recognized by the Public Utility Commission of Texas. They are certified by them, they can sell to the retail customers, but then they have to bring that load and the resources to what we call the qualified scheduling entity or QSE to be scheduled through the ERCOT ISO. These QSEs must self-provide all wholesale energy to serve their load, and they can provide, don't have to but can provide their ancillary services. ERCOT does not operate an energy or spot market, or a spot market. We simply deal with the schedules that the QSEs bring to us.

We do operate an ancillary service market for those QSEs that do not self-provide their ancillary services, and we operate a balancing energy market for the whole interconnect. We'll talk a little bit about that in a minute.

We then settle all wholesale energy accounting between the QSEs and then the QSEs settle with their individual competitive retailers.

(Slide.)

Feel free to ask questions anytime if you'd like to. We've been asked why we went to single control area operation within ERCOT. It was a long decision after a lot of discussion. I think it was basically and foremost an issue of fairness. We operated, as I said, a wholesale competitive market for four-and-a-half years, and in that time frame, we realized that control area generators and control area load had an unfair advantage over non-control area generation and load by virtue of scheduling balances basically in order to control the frequency and do the things control areas do, they used inadvertent energy to settle their imbalances where the non-control area entities often had some pretty stiff tariffs for their imbalances.

We did work on ways to turn that into cash. We spent a lot of time working on turning it into some form of financial transactions. What we found was that in order, if you don't penalize the control area for what it is supposed to do, that is, to control the frequency and the transmission unloading, it's really hard to come up with a financial tool without really just sort of trading money in a circle based on inadvertent energy.

Secondly, we did it for simplicity. We had ten control areas. We knew that the competitive retailers would be selling in more than one control area, and we just realized it was simpler to settle as one control area rather than first between ten, and then between the competitive retailers within those control areas, and then within the competitive retailers across control area lines. This way we can do one settlement and it's accomplished.

Finally, it just fits the market. ERCOT has a lot of functionality in the retail end that I'll talk a little bit about in a minute, and since we do a lot of the retail things, it just made sense to do them within one control area rather than having to do it in ten separate areas.

MR. KELLY: Sam, question. What was the cost of the conversion to a single control area and was it an overnight conversion, or was it that as old equipment got phased out, you moved to a central entity?

MR. JONES: It was a one-step conversion. We actually installed new power and market operating systems within the ERCOT facilities to operate as a single control area. The QSEs that were created, many of which for the old control areas which were generation control, in most cases had to install new equipment. Some of the municipal and coop control areas could make a conversion pretty much with what they had, but there was quite a bit of new equipment, a totally new system for ERCOT. As far as the cost, it would be very difficult for me to break that out. It was a part of our overall cost including our facilities, communications and everything. The retail and the wholesale was so intermixed, it's very difficult to say the exact cost for a single control area conversion was a certain number of dollars.

CHAIRMAN WOOD: What was the total, Sam, for retail and wholesale?

MR. JONES: The total wholesale and retail conversion cost was in the neighborhood of $120 million for facilities and systems.

(Slide.)

MR. JONES: How does the single control area work? Well ERCOT is the frequency control point within our region. The QSEs do not control the frequency, they control to a signal from ERCOT based on several elements but basically ERCOT operations deploys balancing energy, regulation, and spinning reserves to control the frequency and the transmission loading of the interconnect.

In order to accomplish that, we require the QSEs to submit day-ahead 15-minute interval balanced schedules to ERCOT. Every 15 minutes, they will designate their load and what resources or how much of their generating fleet will be used to meet that load. They can adjust those schedules at any time up to one hour ahead of real time based on their observing possible changes due to weather variations and also to correct for congestion if they want to do that.

They also submit day-ahead ancillary service bids for providing ancillary services. They also designate how much of their own ancillary service requirements they will self-provide and how much ERCOT should procure for them off the market. They also submit balancing energy bids up to an hour ahead. We clear that market every 15 minutes for use 30 minutes ahead of when we clear it, because we have to have time to notify the QSEs they've been selected for them to arrange for the generation to occur. So using those every 15 minutes for balancing energy, and then on a real time basis, for regulation, we control the frequency of the grid. We also deploy balancing energy to accomplish that frequency control, but we also use it to control congestion, zonal congestion on the grid, and we'll talk a little bit more about that in a minute.

We can also do generating unit-specific instructions to do local congestion. Then finally we can issue at any time verbal instructions to QSEs if needed for reliability purposes. We occasionally have to do that with a mis-load forecast or something that occurs in the system that needs correction on a very quick basis.

Our transmission service is probably a little bit different from what you're used to. All transmission service in ERCOT is network, postage stamp transmission service actually by our law. Senate Bill 7 that created us specified that network service. All the load entities pay for their transmission service based on their load ratio share. Basically, we take the annual transmission cost of service as approved by the public utility commission and then divide that up on the load ratio share for the load, and they pay their share for the year. There's no charge for transmission service for any energy that does come in over the DC ties because it serves those load entities. But for any energy that goes out over the D.C. tie, there is a formula for charging just for that short-term transmission usage.

(Slide.)

All schedules submitted by the QSE to ERCOT flow.

We don't have reservations, we don't have priority of service, we don't refuse schedules. Basically, all schedules flow and it's possible because ERCOT operations is charged with managing the congestion that might result from those schedules. And again, we'll talk about congestion management in another slide. The cost of congestion at start-up which began July 31st last year was a general uplift initially. We had no real estimate of what congestion costs would be. There was a lot of discussion. Finally, it was decided, as a general uplift, unless it reached $20 million in any 12-month sliding window, then it would be directly assigned to those entities that caused the congestion.

We started the market over the peak of the summer, we experienced an unusual number of generation outages in a pretty short time in one of the congested areas and we hit that $20 million in 15 days. So that gave us a six-month period to implement direct assignment to those entities that are causing that, and that will occur February 15th. Our systems are now being changed to provide that, and we will be direct assigning after February 15th. The losses are calculated by ERCOT staff in advance and provided to the QSEs. They include that in their load generation schedule. Any inaccuracies in that just rolls into what we call unaccounted for energy. That's a general class of energy like meter error, theft of service, loss, things of that nature and UFE, once we've gotten our systems to the point where we're getting good data, has really been quite low. So that's really being well-managed. Finally, the transmission providers, which we call TDSPs or transmission and distribution service providers, they're still regulated in the ERCOT region by the Public Utility Commission of Texas, and they are now in most cases where it used to be the old IOUs, they're now organizationally separated, separate companies from the non-regulated portions of their business.

Within the coops and municipals, they're at least functionally separated so that there's separation between the scheduling activity and the transmission function.

(Slide.)

Our ancillary services is pretty traditional regulation, responsive spinning reserve which is a set number year round based on reliability: the loss of the largest nuclear unit, and then non-spinning and replacement. Again, we take bids for those day-ahead every day for the 96 intervals, all ancillary service providers must be certified by ERCOT. We have a standardized certification process for that. Generators can provide that service through a QSE.

Balancing energy is not an ancillary service, it's a market and then black start is an annually contracted function by selected zones. We basically go and determine appropriate levels of black start reserves that we'll need in the various geographical areas of ERCOT. We go through a competitive bid process and then select the providers. Once a provider is selected, then we certify those units for black start. We've gone through that late last year for this year and have all the contracts in place for 2002. We do offer reliability must run generating contracts if the ERCOT ISO determines in fact they are needed. We do not currently have any RMR contracts in place, although we just have determined the need for our first one in the West Texas region, and we are currently negotiating with the generating company for that unit to get our first RMR contract in place.

(Slide.)

Congestion control has been an interesting experience. When we change from our old wholesale model, where we did have transmission reservations and we did refuse schedules over the capacity of the transmission system to a total open market, we saw a major shift in the flows. The generation patterns changed drastically and we went through a very quick learning experience on congestion management because we were on peak and it was a very challenging process. We're doing that now on a regular basis. Again, it's interzonal congestion is managed by

ERCOT operations staff using zonal-specific balancing energy bids. When we take balancing energy bids, we take by zone. We have four zones this year. If there's no congestion in the system, then the balancing energy clearing price is the same because we just take the lowest out of the bid stack and we don't care where it comes from because there's no congestion. If we in fact have congestion, then we begin to take the balancing energy bids on a zonal basis based on where we need it. Then we can generate a difference in zonal balancing prices based on the bid stack in each zone, and how much we deploy in each zone then to manage the interzonal congestion determines that congestion clearing price.

MR. KELLY: Sam, a question. There's some very high voltage lines around Houston. Their voltage would make you call them transmission and their function might make you call them distribution. Is that all part of the system that the ISO operates?

MR. JONES: Actually, in ERCOT we consider anything to be transmission that's 60 kV and above. I know that's not the case in a lot of the areas. But Texas has so much rural load in small chunks that the 69kV system that we operate down there is just as important to us as the 345. It all has to work together to serve the customer. If we lose, for example, a major 345 line, obviously the 138kV and the 69kV become critical to pick up that difference, so we control all of it and work with all of it through the ERCOT operational center.

MS. FERNANDEZ: Can I ask you a clarifying question on the interzonal? We have a market solution involving selecting the lowest of three or more bids. If there are less than three bids, is that when you move to some sort of reliability contract?

MR. JONES: Actually, yes. For the intrazonal, we've got two ways. One is if there's more than one unit that can solve an intrazonal, which is local congestion basically, we try to get three bids. If any one of those three or more can solve the problem, then we do it based on that bid stack. We found though that that's not always possible for local congestion, especially for areas like the Rio Grande Valley where the outage of a single line for maintenance can cause some pretty severe local congestion. There may be only one unit that can solve it.

So there's really a couple of ways that we can handle that. One if they have already entered a bid for capacity and energy, then we can select that. We can also just order them out of merit, and there's some equations in our settlement protocols that say how we'll settle that based either on heat rates or some other clearing prices. There are several ways that can happen individually. Like I say, we found in many cases that there were not a market solution for three or more units. Basically, we manage congestion at all times so that all schedules flow, along with the direct assignment of congestion costs. On February 15th, we will also start up a TCR activity. It's a financial activity. We'll have a combination of preassigned congestion rights and auction congestion rights. Basically the municipals and coops that owned remote units or had long-term energy contracts prior to the start of the market, will be entitled to some preassigned congestion rights that they paid for based on some historical costs of redispatch. The remainder of those congestion rights will be auctioned annually for some and then monthly for some to any other interested market participant. That auction is coming up very shortly.

I won't spend a lot of time on retail mechanics because obviously that's not a part of this workshop. I just will say that it's a very integral part of our operations. We do operate a centralized retail registration and usage record of meter read functions. ERCOT performs all of the switching activities of customers and it's up to ERCOT to prevent slamming, any switch request, turn on/turn off request, any activity regarding a change in the retail customer comes through the ERCOT systems from the market participants. Actually we do it for the whole state, not just the ERCOT region. To do that, we track and use over five million retail meter reads to actually settle the wholesale market. We settle our wholesale market based on retail meter information. It's complex, it's been a challenge. It was our last full functionality we had to start up to be complete. We went to the full market January 1 on schedule, a little harried, we're still getting some of the small bugs out, but as my boss likes to say, we're on the foreign land, the ships are burned, so we're there.

We've been asked a lot of questions, what keeps our market from blowing up? It was really interesting. When we opened the single control area operations on July 31st, very shortly after that we did have a few days where we lost some generating units and forced outages and our balancing energy actually hit $1,000 for some 15-minute intervals, and everybody said, look there. It's blowing up.

That was not a lot of intervals, and it hasn't occurred very often. But anyway, we think adequate resources are obviously on our side. We've added a lot of generation in the last two years or so, well over 10,000 megawatts. ERCOT's had a very high load growth. In the first four years of the ERCOT ISO operations, we had a 20 percent load growth, 5 percent per year.

We were pretty tight through '99, but we've had the extra generation built. We've got more under construction and more being applied through our interconnection at this time. I think one reason is that our transmission rules are generator-friendly. We tried to see that there's adequate transmission built to accommodate the new generation to hook it up, and it's basically provided by the transmission providers, not at a cost to the generator, to keep everything on a level playing field with the existing generation. That's been a great incentive.

We are currently studying how we ensure adequate generation as we go forward. The region itself was doing some of that work, and then our public utility commission became concerned and actually opened a docket on it, and they're taking input and they'll be working with us on what we do to ensure continued adequacy. We're very hopeful that just the favorable business attitude in ERCOT will go a long way to providing that generation without having to do a whole lot of things from a rules and requirements standpoint to do it.

We're building transmission. We've got numerous projects underway. We've actually dedicated a major double circuit 345 kV line last May that did an awful lot to help us through last summer on that south-to-north congestion. In fact, it was loaded the first day in operation, I think. But we've got other projects in the Dallas-Fort Worth area, the Rio Grande Valley in West Texas, in Central Texas, all over. We've added a number of 345 kV circuits and hopefully we have more on the way.

Our commission has been very supportive in working with us to ensure that, because I think they realize the importance of that to keep an adequate supply for the customers.

We've had four-and-a-half years of wholesale competition prior to entering the retail market, so we hope that experience has also helped us put good rules in place.

We allow 100 percent bilateral provision in hedging long-term if the entities want to do that, so they're not forced into any spot market that can obviously deviate quite a bit.

I think one thing, too, that our balancing energy market, even though it's seen some price spikes for some intervals, it's only about 5 percent of the total energy that is traded within ERCOT, and each interval of the day, the 15-minute interval, 196 today, is just a little over one percent of that day. So a few intervals of one percent or 5 percent really is a small portion of the total energy cost that we incur.

MR. KELLY: Sam, is there anything to prevent people from satisfying 100 percent of their needs from the energy imbalance market by simply not making other provision and then buying imbalance energy to meet their needs, in effect, converting it into an energy market?

MR. JONES: Our protocols actually require balanced schedules, and we have some uninstructed deviation-type penalties in our settlement process. If you don't stay within a certain amount of energy from your submitted schedules, then you're penalized financially for that. It's not a strong penalty.

I think the other way that we would enforce that is just do certification. If we had, for instance, a QSE that just did exactly what you're talking about, then we would probably consider revoking their QSE certification.

MS. FERNANDEZ: Do you look at the day ahead schedule in terms of -- I know yesterday we had some discussion -- in terms of I think PJM and the New York ISO do it a little bit differently -- in looking at the day ahead schedules to see if they believe that they actually look like they're going to satisfy what's really the projected load in real time or not?

MR. JONES: We review that. We generate our own load estimates within ERCOT to compare against what the QSE's are committing.

MS. FERNANDEZ: Does that play into, if you have a balanced schedule and someone intentionally put in a fairly low estimate in the day ahead, would there be a penalty in buying a good deal through the real time balancing market?

MR. JONES: Well, they would just basically pay the balancing energy price. And if we have to go pretty high in the bid stacks, I will assure you there's $1,000 bids in those bid stacks at all times. If we hit them, then they just hit the $1,000 mark for that energy. So there's risk by doing that.

Just some comments. Our experience to date. We originally expected a big bang startup for June 1, 2001, where everything went live. The wholesale portion, the retail portion. It just didn't happen.

First of all, there's just so many things associated with our system, so much stuff, as we call it, it just wasn't practical to try to do it all in one day. So we moved to a phase in to be sure that we did it in a reliable and adequate fashion. We did transition to operations on the 31st of July about two months behind schedule. I have mentioned our power flows shifted significantly when the rules changed.

We went through a learning process but were able to deal with it adequately. Our prices have remained I think reasonable. We started up during the height of the summer in August, which is our peak month, and the ISO does not see the energy prices. Basically for most of the energy, we hear about some of them, but I think they've remained quite reasonable, and I think a lot of that is due to the adequacy of resources in the region, other than just a few days where the balancing energy got high for some intervals.

It's been a major learning experience for us, and we go through a learning experience really as the seasons change because obviously operating characteristics change. So this first year through, every season has been a new day.

Our protocols did not anticipate everything that could occur. I think if you look at the grand scheme of things, they cover most situations. They're adequate. We found a few things they didn't like. When our computers froze up temporarily and we went to manual operations, they didn't provide for that. But our settlement staff has been pretty creative working with the market participants for those few periods.

I will say, too, we've got good flexibility to change our protocols. There's a change process in place where if we find something that just doesn't work right, we can fix it in a reasonable period without having to go through a huge hearing process.

And finally, we learned that gaming has and will occur as experience is gained in any new market, you've got some creative people that are trying to make a profit, and if something's allowed under the rules, they're going to find ways to do it. That's part of the competitive market. The PUC of Texas has a market oversight division, and they perform market oversight for our market. We do not do that, other than just giving them the information they need.

And we found some problems with the protocols at ERCOT that resulted in some opportunities to, I won't say game, but to use the rules to make money, and we're changing the rules as we go to correct that. But it's not been excessive.

With that, I'll stop and just ask if there's any questions the group might have.

CHAIRMAN WOOD: Sam, can you talk a little bit more, because we had a lot of discussion yesterday about congestion management models. Can you talk a little bit more about the change that's going to happen next month and some of the details of that, if you know them? Direct assignment of congestion costs to the congestion causer.

MR. JONES: Yes. Basically I'd say we for zonal congestion, interzonal, where it's zone-to-zone, which is a major part of our congestion, a lot of that can be solved, like I said, with the zonal balancing bids, not all of it.

We found that some of it actually requires some generation that's on the boundaries of those zones that we move out of merit and they're designated still as interzonal congestion, even though it appears to be local, because it's the result of zone-to-zone scheduling.

But anyway, we can identify the cost of that interzonal congestion just through experience and a few protocol changes. That will basically be assigned to the entities that are scheduling across those interfaces. We will assign that to them based on the number of megawatts and the cost of the congestion clearing prices. It's one cost per interval for clearing that congestion interzonally. And so we will assign that cost to those people scheduling there.

They have to pay that congestion clearing cost no matter what. The hedging rights are more financial in nature. Basically, they'll have a certain number of megawatts of TCRs, transmission congestion rights, and it's a financial hedge. They'll be reimbursed for that congestion based on the shadow cost of clearing that congestion. That's independent of what they paid for it. They bought the congestion rights at an earlier auction or they were preassigned as a certain cost.

But once they hold those and they're good for that month or that year that they bought them for or acquired them for, and they are reimbursed each time there's congestion based on that shadow price of clearing that congestion for that period of time. So, you know, there's some risk still that if they bid highly for the congestion rights, they only make their money back if congestion costs go high. And we don't have experience with that yet. We'd just be doing this beginning in February, so it will be a learning experience as we go forward.

Local congestion, like I said, it's more the movement of individual plants in a very small area because of transmission line clearances normally. SOmetimes it's because of loss of generating units. The rule also says that if that price exceeds $20 million in any 12-month window, we will go to direct assignment for that as well.

We just had some disputes on some settlements regarding some capacity payments on local congestion that we're probably going to have to go back through and resettle, and it will come very close to moving that local congestion cost to $20 million. I don't know if we'll hit it or not. It'll be close. But I think it won't be long before we'll hit that trigger point and we'll be looking at how we assign local congestion. That's not determined yet, and it'll be an interesting discussion as we work on that.

COMMISSIONER BROWNELL: Sam, could you talk about your change process? You said you felt pretty comfortable that it was efficient and you were able to respond quickly. That's been an issue in some other parts of the country, so maybe you could tell us how you do it.

MR. JONES: Okay. Basically, our protocol change process was approved by the public utility commission as a part of our overall protocols. We have an active stakeholder process. Everything's done through the stakeholder process in ERCOT, including the customers.

But anybody can initiate a protocol change. They take it to the Protocol Change Subcommittee, which is a standing subcommittee with representation from the stakeholders. They generally will work with the various work groups within ERCOT to see what the protocol change looks like. Is it a retail change? Is it a wholesale change? Is it a reliability change? And it'll come up through the various subcommittees of ERCOT to develop what the change is.

Then it goes to the Protocol Revision Subcommittee for final recommendation. It's debated there. It then goes to our Technical Advisory Committee, which is the advisory to the Board on technical issues. They will debate it and either approve or deny the change or remand it back to the various work groups to work on. Then finally it goes to the board for approval.

It does not have to go before the Public Utility Commission of Texas. However, if it's contested in any way, it can very quickly be brought to the Public Utility Commission for further consideration. So there is protection there to oversee what ERCOT's done on changing those provisions.

We've approved a number of protocol changes to date. I don't think any of them are contested at this point that I'm aware of. We've implemented them, and there's a number still proposed that we work on today.

MR. CANNON: Sam, when you get to this point of auctioning off these transmission rights or assigning them for some cost, what happens to that first influx of dollars? Where do those dollars go?

MR. JONES: I don't know. John?

MR. MEYER: Those dollars will go to all loads on the load ratio for all load-serving entities.

MR. CANNON: So back to the transmission service provider?

MR. O'NEILL: That's because they pay for the transmission system on the share so they get it back.

MS. FERNANDEZ: For the people who are listening, we may need to repeat that.

MR. JONES: John Meyer is one of our experts in the stakeholder group. In fact, he led most of our stakeholder activities. But the money from the sales of the TCRs go back to the customers, because they're the ones who paid for the transmission system to begin with.

COMMISSIONER MASSEY: Would a congestion management system based upon something like locational marginal pricing work in Texas? Has it been considered? Is it something you would look at? How do you see that as a possibility?

MR. JONES: Commissioner, it was definitely looked at as part of our stakeholder process early on. I sat in some of the meetings where it was hotly debated. There were kind of two camps, zonal versus locational. The majority went with zonal. We didn't think that within the ERCOT system there were enough zones really to warrant a full LMP process. Would it work? Sure. It could be implemented.

I think what we're seeing, though, is sort of an intermediate or in between type state. We went with the three-zone zonal type method for our first, say, six months of operation or until the end of 2001. In looking back at that, two things happened once we decided that we needed four zones for 2002. So we did increase the number of zones.

We also saw that there were some changes, enhancements needed right at the boundaries of those zones that we made some minor changes to. I don't think at this point there was any movement toward LMP, just based on our first, say, five or six months' operating experience.

COMMISSIONER MASSEY: The thinking is that the system is robust enough that a zonal approach will work reasonably well without a lot of socialization long term?

MR. JONES: I think that's right. We're making a definite attempt to add transmission as we need it because we found usually if we've got a commercial consideration for transmission, we've normally also got a reliability issue associated with that. So we're trying to add transmission and keep a robust transmission system in the ERCOT region.

CHAIRMAN WOOD: Sam, you mentioned that for the local congestion, there's also a $20 million cap that was perhaps close to being pierced at that point. What type of fixes would come in to address local congestion at that point? Is there anything left other than locational marginal pricing?

MR. JONES: Chairman Wood, I don't know the answer to that question. I know there's a bunch of opinions.

(Laughter.)

MR. JONES: I know there's a lot of concern and proposals out there when that effort gets started. Obviously, once we say we've pierced that cap, the stakeholders are going to be hot and heavy into solving the problem, and I want to listen to that discussion.

I really don't know what they would devise at this point, but I think it will be a real challenge.

CHAIRMAN WOOD: Just so you all understand the framework there, I think we all know locational works really well when you need it. So what we had stuck in -- well, the stakeholders stuck in the $20 million, and because our consultant, Dr. Horn, was concerned that local congestion could also eat up all the gains there, the Commission also stuck in -- they said we're directly going to assign it not just to zone, but to individual locations at certain thresholds.

If those get hit, then I guess in my mind it was kind of inevitable, you've got to go that way. But we just didn't want to start there and design the software so it would be accommodating if we had to switch over. It won't be simple. Is that fair?

MR. JONES: I think that's right, yes. It's interesting to note, local congestion has really not occurred at the same rate as the zonal congestion. It's been smaller. I don't even think we'd be at the $20 million point if we hadn't had an issue early in operations where we had some folks that didn't really understand initially how that bidding worked, and they entered some bids that when we put them in our settlement algorithms, it blew up.

We had several million dollars in just a couple of days. And once we realized or got experience with that bidding process, I know that same entity changed their bids, and their bids have been very acceptable since that timeframe. But I mean, it was there, it was done. So it's in the total, just not nearly the amount of money, though, that's in the zonal portion of our congestion.

MR. KELLY: Just a follow-up question on the control area issue. As a single control area, do you directly control all the generation you need to keep the frequency constant, or is it a master satellite system where you send instructions to satellite control areas that then control the generation in their local zones?

MR. JONES: It's a master satellite-type concept.

Basically, we do all of the frequency control from the ERCOT operating center. We have a bias and that type of thing. We sample the frequency. But the way we do it is by sending a generation control signal to the QSEs that are under our control. That signal has no frequency component in it other than what we've entered as far as the generation requirement to control the frequency. It's basically a combination of the schedule they gave us for that 15-minute interval.

The balancing energy that they've been awarded for that 15-minute interval, the regulation signal, if they have any regulation for that particular interval, and any other ancillary services like no-spin or whatever. So we combine all those together to make an instantaneous signal that we update to them every two to four seconds. They're supposed to run their fleet to that signal. If there's any zonal in there, it would also vary by zone, but not by individual generating unit until we go to a specific unit for local congestion.

We do not actually have direct pulsing from our systems to any generator, so we're dependent on the QSEs to follow our signals relatively closely to maintain their frequency.

CHAIRMAN WOOD: Can you describe the planning process as it is now? I know it's kind of moved on since I left. But I just wondered how does the ERCOT planning process work?

MR. JONES: I assume transmission planning. We have a transmission analysis section on the ERCOT staff. Basically, the ERCOT transmission rules, the PUC rules, require that ERCOT oversee or supervise all the transmission planning for the ERCOT region. We have developed within ERCOT what we call regional planning groups. We do not do all the planning at ERCOT. We think there's a lot of knowledge and value of those experienced transmission planners in the individual transmission provider companies.

We will work with them on a regional basis. For instance, you mentioned Houston. We've had transmission concerns in and out of Houston lately. We'll work with the group that owns transmission in that region. We have a North Texas group that's pretty large.

The Dallas-Fort Worth area, which has been kind of a black hole of electricity in our system. We've got another for West Texas, one for South Texas, and we work with those transmission providers to determine what the problems are, what the best solutions for those problems, which lines, for instance, if upgraded or added would have the major bang for the buck.

We also review a proposed project if the transmission provider comes to us, based on serving load in their region, and we think this is a good transmission project, we will review that with them. Through that process, we come up with recommended additions which we will then have open -- I don't want to say hearings -- but open meetings which they would post what the projects are. We don't post routing, that's not our function. We post point A to point B. We will have open sessions where anyone can come and make comments or they can send us written comments. We factor that in, then in the end result, we go to the board and say, these are transmission projects we think need to be added in ERCOT, here's our justification. The board then either approves, supports, or doesn't support those projects. So far they've supported all of them. Once we get board approval, we will notify the transmission providers who they are. Right now it's usually the companies that own the ends. At the same time, we'll notify the Public Utility Commission that we have approved these projects and we think there's adequate need for these projects and who the providers are.

Then it's up to the transmission providers themselves to go to the Commission with their certification process and get those lines approved. We will work with them as far as providing support on the need for the project. Actually, the transmission rules within ERCOT now say that our recommendation for the most part establishes need for those projects, although that's considered by the Commission certainly a part of the permitting process.

MR. O'NEILL: Sam, once you approve a project, do the existing transmission owners have the exclusive right to construct those lines, or could other entities come in and construct those lines?

MR. JONES: That's really a good question. Several things have happened. First of all, we are not of the opinion they have the exclusive right. We've just not had anybody come up to us yet and say, I want to be a new transmission provider. Some companies have talked about it, but none have. We will certainly consider that factor if it's there. I think there's some concern that it would put some of the companies that might want to do it, we'd classify them as utility, and maybe they don't want to do that. I don't know. I can't speak for their individual concerns. But we are open to that process, it just has not happened. We've had some other variations, though. We have designated some providers and they have come forward and said, you know, I don't really want to do that work. In that case then we've designated other providers. In some cases, they've gone and found another transmission provider and worked a deal on the side, and come to us and said, hey, we want to it, here's our arrangement. That's fine.

So if we designate a provider and they don't say no, then we expect them to perform. If, for any reason, we look and they're not actually doing the certification CCN work, then we'll have to say, hey, we're going to have to give it to somebody else. That has not occurred to this point.

COMMISSIONER MASSEY: Your slide presentation with respect to the single control area issue just says flatly, in answering the question why fairness control area entities have an unfair advantage over non-control area entities in a competitive market. That would be true not only just in ERCOT but in all control areas, would it not be?

MR. JONES: I don't want to get stoned here.

(Laughter.)

MR. JONES: I think, based on my experience --

COMMISSIONER MASSEY: The answer is yes.

(Laughter.)

COMMISSIONER MASSEY: We can just move on.

(Laughter.)

MR. JONES: I will say if an entity devises a way to turn inadvertent energy into financial reward, and solves all the issues associated with that, there may be a way around it. We were not successful in doing that in the time period we looked at it.

COMMISSIONER MASSEY: Thanks.

MS. FERNANDEZ: If there are no other questions, we'll let people go to lunch. Thank you very much for your presentation. Could we get back together at 1:30.

(Whereupon, at 12:30 p.m., the Conference was adjourned for lunch, to reconvene the same day, Wednesday, January 23, 2002, at 1:30 p.m., in the same place.)

A F T E R N O O N   S E S S I O N

(1:40 p.m.)

MS. FERNANDEZ: Could people start getting to their seats so we can get started in a few minutes? If we could get started, if people would go to their seats. Let me sort of start off and welcome people back for the afternoon, and sort of start out with, you know, this has been so much fun having the Conference that we decided we'd have another one. The Commission's going to be issuing a notice probably either today or tomorrow that will list the dates. We're going to have a conference again February 5th, 6th, and 7th. I think we're going to be inviting speakers. The topics we are going to, in the invitations, we are trying for cross sections of all the various industry groups. The topics are going to be energy markets, operating reserves, transmission rights, and hedging instruments, generation adequacy, transmission tariff implementation issues, market mitigation, and ways of minimizing the cost, one of the main ones of which is software issues.

As I said, that notice should be coming out either today or tomorrow. To start of this afternoon's panel, we have representatives from two ISOs or IMOs that did not give presentations, so to start off with, I'd like to give them the opportunity to make a few brief comments, a description of the market design, and also some of the changes that are being looked at. We have Steven Greenleaf from the California ISO, and Amir Shalaby from the IMO Ontario. I'll let Mr. Greenleaf start off.

MR. GREENLEAF: Thanks, Alice. I'd first like to thank the Commission for the opportunity to be here today. Secondly and probably more importantly I appreciate the opportunity to briefly summarize where we think we're headed as part of our market redesign initiative. I think that's probably an important context to set for this afternoon's discussion and is relevant with respect to many of the issues currently before the Commission.

Before I do that, I'd like to set a little context as far as some of the principles we are working from as we go through our market design initiative. First of all, I think a lot of these issues and a lot of these themes were talked about over the last couple of days, and are fairly consistent and flow through from one organization to the other.

First and foremost, we think market design needs to support stable operations, and reasonably stable prices. We can define that later. Also, at least from our perspective, the market design needs to support and facilitate satisfaction of the core functions of an ISO which, in essence, and fundamentally is the provision of non-discriminatory transmission service. In addition a key principle as we move forward, certainly in California, we think the market design needs to support transparency, both with respect to price and operations. Thus we think there really needs to be a high correlation between the price as established in the RTO's markets and the operations of the grid. Certainly we heard yesterday that market designs need to be flexible and at least from our standpoint need to provide a menu of services that really satisfy the needs of all the customers on the grid. Certainly there's a diversity of customers, certainly that's true in California where we have entities vertically integrated utilities functioning hand-in-hand and alongside those who are more merchant in nature.

Let me say that in the context of our market redesign effort, we really are truly examining what we think are best practices from around the country. And as I go through and highlight some of the details, I think that will become evident that we are proposing going down a road that really combines what we think are the best practices. Certainly there's features of the California market, yes it is true, there are features of the California market that we think are successful. For the last three years, we have operated a multi-settlement system with day-ahead, hour-ahead and real time settlements. We have facilitated viable markets and ancillary services, spin, non-spin, regulation and replacement reserves. And we believe that the method of our auctioning and the specification of our firm transmission right product was and is a valuable approach and a good approach for ensuring that market participants have financial hedges, a financial hedge.

Let me quickly walk through, and I know you want to do this quickly, and I will attempt to satisfy that, some of the primary features of where we're headed. There's really ten elements and I'd be happy to discuss the details as we go forward.

The first is the adoption and institution of an available capacity requirement in California. This is a completely new feature to the California market, but one we think is absolutely critical going forward for two reasons. One, it reestablishes what we think is an appropriate responsibility on load-serving entities to ensure that sufficient capacity is introduced into the market and made available to the market. Secondly, it satisfies a critical need as we come to the end of the Commission-established west-wide price mitigation. We think this is valuable and necessary feature from the current must-offer obligation in the west going forward.

Secondly, we're proposing significant changes to our congestion management approach. At this point, I should caveat that the proposal is preliminary and there's a lot of work to be done and a lot of issues and questions unanswered, but we are proposing to move to a locational marginal pricing approach using a 3,000 bus detail network model. I think the vernacular is bid-base security constrained dispatch. It's a mouthful. We haven't had a lot of practice saying that.

(Laughter.)

MR. GREENLEAF: Certainly an application of both day ahead congestion management and for real time purposes, that'll be the basis -- we think that'll be the basis of how we move forward. On firm transmission rights, as I said, I think we have a viable approach to the auctioning in making them available to all market participants by necessity, moving to the detailed network model in conjunction with other design elements. We think there'll be some modifications to the FTR. Right now, their direction and pass specific in California and we anticipate moving to probably a combination of point-to-point, point-to-hub, et cetera, type of trading rights.

Moving on, forward spot market for energy, obviously the Commission is aware of their directive to California to propose a plan for institution of a day-ahead energy market by May 1st. We have obviously taken that admonition seriously and are examining that in the context of development of our day-ahead congestion management. Part and parcel and goes hand in hand with the available capacity obligation is the need for what we're calling a residual day-ahead unit commitment process. I won't get into the details, but I think it's pretty similar to the reliability assessment that Andy Ott walked through yesterday for PJM. But there are details of that yet to be specified. We're examining necessary changes to our ancillary service markets. We do think we've operated viable markets for operating reserves and regulation in California.

But by necessity of moving to locational marginal pricing and other aspects, we're examining changes to that. Hand in hand with that, we're also addressing necessary changes to our real time market. We can get into the details of that soon. I'm sure we will.

Let's see, then the final two elements are an ability to do real time bid mitigation. This once again is what we think is a necessary element that we need to have in place by the end of September when the Commission's west wide price mitigation measures expire.

Then lastly, a damage control price cap on the ISO markets similar to that in place in the eastern ISOs.

That was a very quick overview of some of the major design elements, and I'd be happy to answer questions as we go forward.

MS. FERNANDEZ: Do I take it, in general the way you've described it, it sounds like the market design that you are proposing is fairly close to what PJM has, fairly close to what New York ISO has?

MR. GREENLEAF: I think you really have to take it on a function group by function or feature by feature basis. There are some elements that are quite similar but others we think are a little different and really this goes to the theme or the principle I enunciated first; flexibility accommodating all the needs. I think there are certainly special circumstances that we need to address, special circumstances or regional differences that exist in the west that we need to be prepared to accommodate.

MS. FERNANDEZ: What are the areas where you're highlighting the differences, the regional differences? What are the areas where you're putting in elements to deal with the regional differences?

MR. GREENLEAF: It's not being prescriptive from the start. I think Steve Walton did an excellent job this morning of describing some of the limitations and some of the accommodations that need to be made to accommodate energy limited resources. Certainly California isn't exactly the same as the northwest, but we do have substantial hydro. Approximately 25 to 30 percent of our installed capacity is from hydroelectric resources so we, by necessity, have to address those concerns. I know there's some flexibility there. I think some of the aspects or features of the New York market that we heard about yesterday attempt to address those concerns, so we're in the process. The issues are not resolved but that's one of the issues, the extent to which you do unit commitment.

MR. MEAD: Let me ask one question, if I could. You said at the beginning of your presentation that market design should, among other things, support stable operations. Are there particular aspects of this proposal that you have just described that help achieve that objective? Are there things that California or that the ISO is proposing to do here that better supports stable operations?

MR. GREENLEAF: Some of the changes we're contemplating not only in the real time market, but as part of day ahead. It's really, you know, the base of that of course is application and implementation of a detailed network model which really provides an accurate assessment of what's going on on the grid. But it really gets in part to the transparency issue, it's predictability, it's transparency. And there's features that we're examining. It's hard to point to the specifics at this point but it's really attempting to move to a paradigm where the prices we set are truly reflective of operations on the grid, so it's that high correlation between price and action. Legitimately, over the last few years, I think there's been some concern that some of the price signals established by the ISO don't necessarily have a high correlation with what's going on on the grid at any given time.

MS. FERNANDEZ: If I could ask briefly, what sort of a timeline for the proposal for the refinance?

MR. GREENLEAF: Certainly. We are somewhat constrained by the Commission's directive to file our congestion management and plan for a day-ahead energy market by May 1st. Right now, we're planning and proposing to put the comprehensive design proposal, a fairly high level proposal, before our board on the 7th of February and then subsequent to that, filing it before the Commission.

MS. FERNANDEZ: Thank you. Let's move on now to Mr. Shalaby.

MR. SHALABY: Thank you. I start by thanking the Commission and Staff for affording us the opportunity to be here and encouraged by the Chairman's interest in the fit between the midwest ISO and the northeast markets to the Canadian provinces. That certainly is a priority with us as well. The natural market extends north of the border. There's 4,000 megawatts of interconnection between Ontario and three states; Michigan, New York, and Minnesota. Extensive trade, maybe not as extensive as it used to be at one time, but an extensive pattern of trade between the provinces and the states below them. So reliability issues and market issues bring us to take interest in the standard market design and all the RTO issues.

We've been active in submitting comments on the NOPR way back in 1999 and have been participating fairly actively ever since in the discussions that have taken place here.

A quick sketch of Ontario. Ontario's size electrically is about the size of New England or New York, 25,000 megawatts of peak demand diverse generation mix, a little less than half nuclear, a little more than a quarter fossil, mostly coal, and about a quarter hydroelectric.

The hydroelectric that we have does not have the storage capabilities that you heard about in the northwest today. It's a lot less in terms of shifting its energy into peak and firm demand. We have four transmitters in the province, dominated by one called Hydro One. We have 90 distributors in the province of various sizes and varieties. We have a number of generators, probably 30 or 40, a dominant one, Ontario Power Generation Company. There is dominant Crown ownership of the main utility elements in the province that's set to be privatized and divested over time. Major restructuring in the provinces started in the mid-90s by leadership of the provincial government and something that you're familiar with of course in the Canadian climate, the provinces have most of the mandate on electricity policy matters and electricity regulation, so the Ontario Government led the restructuring in Ontario and by act of legislation they restructured the sector completely, total unbundling of generation from transmission, from distribution, from retailing, so we're 100 percent divested, no integration of utilities at this time. The independent market operator was created as part of that act of Parliament, so we get our authority by act of legislation. The independent market operator has many of the authorities that the RTO powers and functions describe and talk about, and some more, given the regulatory climate in Ontario.

Some of the features of our market, to answer Alice's bottom line question, are you similar to New York and PJM, the answer is yes. We've had the advice of consultants and theory that is similar to what New York and PJM have received. So it is compatible in principles, but we've learned over time that compatibility and principles gets you only so far. But that creates a still sufficient number of rough points, disconnects, and seams that irritate everyone and stand in the way of trade and the flow of trade.

So compatible in principle is a good comforting first point, but not compatible in all procedures at all interfaces and the details of all the markets. We've been working to iron seams out and to sand all the rough edges, somewhat successfully in some aspects and less successfully in others, and we'll continue to do so over time.

One last point about our place in the evolution of markets. We're two or three years behind where PJM is today and where New York is today in terms of we've constructed our markets, we've designed our markets, we've unbundled our industry, but we've not operated our markets wholesale markets yet. That date is set for May 1st of this year.

So we come here with an extensive design in place, with extensive rules in place, with extensive IT infrastructure in place, extensive training, extensive procedures but no operating experience yet. So our contribution is limited by the sort of no-scars-on-the-battlefield-yet. We have not found what works and what doesn't. We know from everyone that you can design the most perfect machine in the world, but if you take it out to the field, some things will not work as anticipated.

The response of participants will shape the need for modification and evolution. So we fully know that we will evolve and we will change over time, conditioned by the experience of the marketplace and the participation.

We have two or three pieces in our design that are not complete yet, and we're aware of that. Most significantly is locational marginal pricing within the provence. We have locational marginal prices across the boundaries to New York and to Michigan and Quebec and elsewhere. So bridges out of the provence have locational marginal prices on either side of them. But within the provence, we have uniform prices to start.

Like everyone else, like Texas, there hasn't been congestion when things were centrally planned and operated. We don't have extensive congestion in Ontario, but we full know when the markets open and the rules of the game change, congestion is very likely to occur in places we haven't anticipated, and we are getting ready for that as well. But we're going in with adequate transmission capability, and with adequate distribution of generation resources to hedge the risk of significant congestion going in.

So LMP is in the cards, but not implemented yet, and will be discussed with our participants and stakeholders before implementation.

We also don't have a day ahead market. It was in the original design, but been postponed. And also it's in the cards and being debated, what features of the day ahead market we will put in place.

I can go through the tables and maybe I'll make the commitment here that we'll fill the comparison table that the Staff circulated yesterday. We'll also submit material comparable to the slides that our colleagues have presented here over the day and a half that would describe the Ontario market in similar categories and terms. We tend to describe our market a little differently, but we may and will adopt the categories and headings that you chose to describe the market and fill in the spaces that way.

With that, I will end my five-minute allotment and participate during the afternoon. Thank you.

MS. FERNANDEZ: I was curious on the last points where you were talking about LMP within the provence and the day ahead market. Is that something that's planned and not implemented?

MR. SHALABY: It is planned. We have shadow operation, meaning we will calculate locational marginal prices in a way that the information will be available and produced. The software is there to do it. We will not settle the market on that basis in the early stages of our market.

MS. FERNANDEZ: And the day ahead market, is that something that's planned or is still under consideration?

MR. SHALABY: It's under consideration. And I failed to introduce my colleague, Peter Sergejewich, who is in the audience, director of market development at the IMO. When I err significantly, there's a dead band about my error. But if I err significantly, he will nudge me and intervene.

(Laughter.)

MR. SHALABY: One added feature that Peter reminded me is that our markets adopt financial models for transmission rights, transmission reservation. We do not have physical transmission scheduling similar to some of the physical transmission concepts that are being contemplated.

MR. KELLY: I don't have a question for Amir, but when you turn to general questions, I do have one. This one is for Andy Ott. And actually I gave him a heads up I was going to ask this. You indicated yesterday that you have a lot of adaptability and flexibility with your customer groups who come to you with special needs. This is sort of a planted question, or at least you had a chance to think about it.

If the people from RTO West came to you as a group of customers in PJM and said we have these special needs, which were described this morning, would you be able to handle them? Or are there some aspects of their special needs that would say, look, you just can't do that within PJM?

MR. OTT: In general, the answer would be I'd probably make them happy. I'd probably say yes. I think the reason that I would be able to accommodate essentially what I heard this morning was a lot of the thing -- the participation options in PJM are voluntary. For instance, the bilateral schedules.

The one thing I would disappoint them on was I would more or less say I think the requirement for a balanced schedule is probably not necessary under a nodal pricing environment. The reason for a balanced schedule requirement would be that you wouldn't have a spot market, so you'd have to keep balanced schedules so that people wouldn't abuse the small imbalance. But since you're going to design it as an LMP system, you probably wouldn't need that requirement. It would actually probably strangle the market rather than help it.

But as far as the self-commitment, I think that's already in our model. In fact, I'd throw out that in our reliability commitment, the way the algorithm actually looks at the day ahead units that are locked in as self-scheduled, even though they weren't self-scheduled in the day ahead market when the reliability commitment comes along, it actually looks that way. In that case, almost all of the units are self-scheduled. It's a very small, incremental commitment.

So it actually has that feature in addition to the day ahead, of course, has it. The ability to use the one part bid versus three part again is an option. So I think in general, the other thing we do offer in our model is if the participant is indifferent to price because of some other requirement, whether that be an environmental requirement, whether it be a river coordination, river flow problem, in PJM we have the Susquehannah river.

We offer a service an hour before our day ahead market. The hydro units on that river all give us their elevations and all their information, and we coordinate the river for them. So we send back a set of coordinated schedules. We pre-load that into the day ahead market for them, and they review them and make sure that's what they want to lock in. So we actually provide that as a service for coordination, because different companies and the Susquehannah River Commission require that they coordinate, so we provide the service for them. It just dumps in as self-scheduled into the market.

But we provide the coordination function. So these kinds of things do interact and do work as long as you have again the flexibility inside the market. Does that answer?

MR. KELLY: It does, I suppose. Alice, we should see if Steve or others want to comment on Andy's answer.

MR. WALTON: Well, sounds good. But I'd want to test drive it first. We are working along. We've made a substantial change in the model thinking, and we're working through that. There are a number of people who are uncomfortable, more than uncomfortable with the notion of an unbalanced schedule. And as I said before, that's not what we're going to propose to start with.

There are those concerns that have to be worked out.

MR. KELLY: Could I just follow up? Sam Jones this morning said they required balanced schedules in ERCOT. They don't have an energy market. You require balanced schedules. You in some sense don't have an energy market.

MR. WALTON: We don't have an energy market in the sense that California is proposing or that you would have in PJM. What we do have, however, is we're going to clear the congestion on a locational basis, which means that we'll have bids and offers made by parties which they'll be used to clear the congestion of the day ahead market and in real time settle imbalances. I suppose those would be thin markets or smaller markets. It wouldn't be PJM West.

On the other hand, there has been very active forward market an active exchange of energy on an hourly basis even amongst the parties for years. So the feeling of the Northwest parties is a lot of that already happens. There's a lot of trade that goes back and forth as people trade their rights back and forth, their energy back and forth, when they take water from one reservoir to another they have in lieu or of certain other transactions that go on there's already a substantial amount of energy trade going on on an hourly basis. Based on that, that's the place they're willing to start at.

MR. KING: I'd just like to comment with regard to the software aspect of this, I think that to the extent that one can parameterize a lot of these needs, you can work within a given software package or framework. For example, early on in our design, we had a history as a power pool of I'll say not having the best control performance compared to other areas of the country. So we put a lot of emphasis on specifying exactly where the generators needed to be.

We found when we first went into operation that we had it wound a bit too tight, but we were able to increase dead bands and allow for additional accommodations to provide some flexibility that allows the generators to participate but not be overly penalized when they fail to perform.

So if you look -- you kind of have to separate what the software functionality is and how it's designed from what the needs are. I believe you can take many of these platforms and tailor them to the specific needs as long as they have all of the functions they encompass all of the main functions that we need. It's just a question of turning some on or some off or maybe using them a little bit differently. But I think that there is sufficient flexibility.

I think we should be encouraging the software vendors to design their products in that manner so that we can deal with these specific needs as we look across the country.

MR. GREENLEAF: I would just like to comment and echo Chuck's statements and position on that. First of all, we support competition, so we'd like the opportunity to go to New York PJM and or anywhere for guidance on how to deal with certain things.

But Chuck makes an excellent point in that, for example, what I heard yesterday in his presentation is that New York has certain stability limitations or concerns as far as their operation, and they factor that into the development of their software. That's certainly a consideration in the West where the nature of our system is such that we do have significant stability concerns or limitations as far as system operation goes.

The approach you talk about as far as best practices is the way to go. It's the plug and play aspect that really is appealing.

MR. O'NEILL: Can I suggest a general principle? That you only assess penalties when the behavior threatens the reliability of the system and not otherwise. Yes, if balanced schedules are needed to essentially keep the system reliable, make the case. But if balanced schedules are necessary or you're going to penalize them just because people think they'd like to have balanced schedules, that's not a very good reason. Certainly you'd want to penalize behavior that essentially leads the system towards instability or overheating lines and things like that. But it's not clear to me just penalties for the sake of penalties, because you've deviated from some norm are justifiable.

COMMISSIONER MASSEY: I have a question. I think it was a month or six weeks ago the Commission posted on its Web site a staff paper on laying out the concepts that staff was recommending that the Commission look closely at as we move forward with respect to standard market design.

For the purpose of my question, I'm going to assume that each of you has seen that. Is that a safe assumption? It's a 15-page paper as I recall, very meaty, a lot of conclusions in it. I'll tell you on the front end that I liked it and generally believe it's the right direction. But I wanted to ask each of you, did you find anything in that paper to which you had strong objections or any objections whatsoever?

Let's start with Steven Greenleaf.

MR. GREENLEAF: Commissioner Massey, I'll be honest. I don't remember all the details of the paper, and the flexibility that was built into the paper. Certainly I think the staff paper went to certain essential elements, but I think with respect to implementation and fulfillment of some of the objectives there, it wasn't clear to me how flexible the flexibility that was built into the concept. And I'm thinking in particular on unit commitment.

I think it was clearly expressed that that may be a necessary feature, and there's different ways to do that, and there's the extent to which you do it. One extreme being totally decentralized unit commitment, and then centralized unit commitment. I think you need to allow for some variation in flexibility based on the circumstances in various regions, as to the need for that and the extent to which you could do that. That's probably the one that jumps out at you the most as far as the need for flexibility.

I think Andy raised some good points yesterday with respect to ancillary services and that, depending on the situations in various areas and established by the regional councils, you may want to allow some variation on the products ultimately offered by the RTOs in the various regions.

COMMISSIONER MASSEY: But with respect to just the big picture features a day ahead market and so forth, any major objections to any of those?

MR. GREENLEAF: I think along the lines of the unit commitments, the day ahead market is going to have to be on a case-by-case basis. In many respects I think we're all aware that California posed special circumstances where, with the demise of the California Power Exchange, really the need for the day ahead energy market became evident, and we moved forward on that.

But in other regions, that may not be the case. There may just be a more liquid bilateral market or just other circumstances which would not necessarily necessitate an RTO facilitating, formally facilitating a day ahead energy market.

COMMISSIONER MASSEY: David?

MR. LaPLANTE: I think the staff paper was fairly consistent with the design that we're putting in in New England and is operating in New York and PJM, so we're fully in support of it.

I think areas that may not be ready for final decision yet are operating reserves and the ICAP market. I don't think there's been enough experience nationally to come to conclusions on standard market design for ancillary services yet. So that's something that may be worth waiting on.

I think each region has different ancillary service needs. Hydro systems are much more reliable generally. So they have a different set of ancillary service requirements than a thermal-based system.

In general, the staff paper is consistent with where we're going, and we fully support that.

MR. KING: I think I would agree with David's comments. The major elements are all there. Where you see differences when you begin to peel away the layers of the onion and get down into the actual implementation details, that's where there needs to be room for flexibility to again mesh the market we all want with the particular operating characteristics of the underlying system that have to work in order to support the market.

MR. SHALABY: The time horizon the paper took was encouraging. The notion of transition into objectives that would be a little further out in time. This is particularly attractive to us, given that we just invested a large amount of time and energy into the market design that we have.

We like the notion of permitting those who have facilities in place some transition to a standard design. That wasn't the specific question given, but I'd like to leave that notion.

On the paper itself, the one thing that gives us the most heartache is the physical transmission aspects of the paper. We have a large number of minor comments, but the singular issue that sticks in contrast to the design that we feel is efficient is physical aspects to transmission.

MR. KELLY: Just a clarification. Is that a problem, if the IMO had to comply, is that a problem that you're dealing with partners in the United States that had to comply and it creates a seam? Or is it a problem --

MR. SHALABY: More the latter.

MR. KELLY: You don't own generation now. Are you doing business in the United States or buying in the United States.

MR. SHALABY: It's more the latter, financial versus physical transmission. The blend of the two creates inconsistencies and difficulties in scheduling transactions across a wide range.

MR. O'NEILL: Let me try to clarify that. If you have an FTR and schedule physical transactions that mimics the FTR, could you say that you had physical rights?

MR. SHALABY: Our design indicates, we indicate its equivalent.

MR. O'NEILL: There we go. There's physical and financial rights in that sense?

MR. SHALABY: It's equivalent. It achieves the same objective. But we don't assure somebody this passage for these hours for that amount.

MS. FERNANDEZ: Was your concern that you thought that the staff paper -- I think it raised the question between RTOs and it said that in terms of the day ahead that you could have physical in the scheduling, you would rather have that financial too?

MR. SHALABY: We're trying to wrap our minds around the notion of physical further out, and as it closes in, it becomes financial. There is some attraction to that notion. Our view still is that you don't need it either farther out or at the time. You don't need it anywhere on the horizon. It's a lot less problematic if it stays in the farther out time horizon than if it comes further in.

But our view, again, I condition all of that with people whose operating experience perhaps would better identify whether you do need it further out.

MR. KING: I would just like to add to that that regardless of which particular system one chooses to standardize on, the real objective here is transaction certainty. The parties scheduling a transaction across multiple areas shouldn't feel that they're sort of looking at a Russian roulette thing of one side versus the other, that they have some certainty that the transaction that they understand how the transaction will be treated and evaluated.

If it's a go in one area, either it goes in the other area or not. But they know that right away. I think that should be the goal, and then look and see which system allows you to arrive at that in the most expeditious manner.

MS. SHIMLER: Mr. King, you said that you agreed in general with the major elements of the staff's paper and you followed up by saying that differences come with implementation of the details. And you said that about transaction certainty. The details that you are saying are differences, can you expand on those? Because my concern goes right to your second remark about smoothness of transactions, especially as we go from one area to another.

MR. KING: That's one area that we've been working extensively in with both New England PJM or working with the IMO as well to evaluate how transactions are being treated now and how they will be treated in the new market and trying to make sure that as we transition into this market, we carried along a lot of legacy operating practices that we found were just not adequate, so we had to correct those, improve the data communications between the control areas to avoid failure of transactions as we move forward, and we've had to deal with a number of different things.

For example, PJM uses a ramp management protocol that is different than we use or actually anybody else that we know. So we're designing a ramp management system to mesh with that, okay? They have ramping issues they need to deal with, and they've developed a system to deal with them. We take no argument with that, but we're designing some enhancements to our scheduling practice to mesh with that.

This may be the only boundary that we need to do that on, but that's an example of how the implementation details become important and how you can -- there was a question that I think perhaps it was Yakout Mansour brought up this morning as how you coordinate seams. What I just described is an example of how you can in fact coordinate seams.

I don't know if that fully answers your question or not.

MS. SHIMLER: Thank you.

MR. PALIZA: I agree with the main elements of the design included in the paper. I think the Midwest ISO market design is very much along the lines that have been described in the paper.

I also would agree with Chuck's comments here that the devil is in the details, especially in the Midwest, where the markets are going to be established for the first time in such a large region with numerous control areas.

I think the implementational aspects of that are going to determine to a large extent what kind of compromises in the design we have to make in order to make the implementation feasible. A couple of things have been mentioned here, for example, like reserves. In a region as large as the Midwest, we may need a unique reserves approach so that we can guarantee reliability.

Regulation is another aspect that we need to work through the details. Having numerous control areas within the Midwest and trying to centralize al that into a single dispatch is not going to be an easy task. Therefore, I think we need flexibility in order to accommodate these particular characteristics of the different regions in order to be successful in implementing the markets in a timely manner.

MR. WALTON: As you heard this morning, we have a host of opinions on some of these issues so there really isn't a central answer to that. Probably the one that has raised the most concern is the notion that all contracts would be converted by a date certain or at least some people read it that way. We spent a fair amount of time this morning discussing that with you and explaining what the anxieties are and the concerns are and the solution we've tried to come up with to deal with that issue. But there are other issues, you know. You can look through the paper and say, we're doing something like this, we're doing something like that. But we're going to implement it this way or that way. So we still have a fair variety of opinions and people back in Portland have been banging away today and yesterday on the metal here of this proposal, trying to figure it out.

So I'm not in a position to take an opinion, other than to point back to this morning so you understand that contract conversion in particular is a very sensitive issue with very wide opinions.

MR. OTT: I liked it. I thought it asks questions in the right areas. I mean, there are certain areas that there are still some questions. Those probably were the areas where the questions still exist. I think there were probably two areas maybe that it didn't touch on or it may have and I may have forgotten, but two come to mind. One is on the issue of data standardization or data interface standardization. I don't recall that being there. It may or may not. With that, I think we talked about this on the phone. I heard a term this morning "FTO". We have FTR, we have TCC, we have CR. As far as the participants who are interacting with these systems, we owe it to them, as a group, to say okay let's call an orange an orange, and let's move on. If it's the same product, all the markets will end up calling it the same thing.

The other thing is a common set of data standards, if you will. Generation data has certain formats. I don't think it would take all of our software development down to have some type of uniform interface into our systems from transaction scheduling and even generation data.

Probably the other area, I think one where we've seen come clashes, and I think that's what Chuck had alluded to, I think the areas of the seams of the market, a lot of the areas are more timing. In other words, PJM has to the west of us and ourselves to the west and south of us, we have schedule changes every 15 minutes. New York accepts them on the hour. And there are some, obviously there are reasons for that but the point is some of the timing of how the market mechanism work may be of interest to stakeholders, if you will, to look at that. And again, one market design has an hourly bidding, another doesn't, so obviously the hourly boundary means a lot more. So it could be very deep into the design and maybe you can't get there but I think we should at least address the issue. That's probably all I had. Otherwise, I think it was great.

MR. JONES: Unfortunately, we've been so busy finalizing the start-up of our retail market, I haven't had a chance to review the paper that you're referring to.

COMMISSIONER MASSEY: Thank you to all of you. I appreciate it.

MS. FERNANDEZ: With that, what we would like to sort of talk with for most of the rest of the afternoon is to sort of basically try and have three basic questions on a number of the topics. I talked with the panelists before. Earlier I passed out something where I showed a comparison of energy markets, transmission markets, reserves markets, and market mitigation among PJM, New York ISO, ISO New England, standard market design proposals, and the midwest ISO's Day Three. In using those kind of general topics, we'd like to go through and talk about what items must be standardized to facilitate trade, what are areas where regional differences should be allowed, and what are best practices that should be adopted.

I'll admit that in doing the chart, it doesn't get into an awful lot of detail, and in some of the discussions that we've had over the last two days, one thing I would like to explore is that in some of these when we're talking about items where you can have regional differences or whether you need to standardize or not, that those are areas where some of the accommodation and flexibility, for example, on the day-ahead and real time markets, if some of the various bidding rules for energy limited resources and the like, if that's an area where you could standardize the general parameters of the market but allow regional variations in terms of some of the bidding rules.

With that, if we could start with in terms of the energy markets, the first topic is congestion pricing. We've heard an awful lot about LMP. It's sort of been an LMP conference the last two days. Is that something the Commission should standardize, require as a basic method?

MR. GREENLEAF: I guess I'm not there yet as far as standardizing the LMP, but I'll go back to core principles and some of the principles I identified first. That really is developing a congestion management tool that really doesn't mask any significant congestion in the day-ahead. The fact is, you know, once you establish that principle, it's easy to get down to the fact that LMP may be the answer. But I wouldn't want necessarily to foreclose alternative solutions. The base has to be a system in the congestion management model that is consistent with and supports real time operation of the grid. That's the most fundamental element that has to be there. I guess we're not prepared at this point to say that LMP is the only answer to that but certainly a detailed representation of the network that accurately represents and supports and facilitates reliable system operation is critical.

MR. O'NEILL: What about the participation on the demand side with these large zonal prices, especially sometimes where you can't get the signal to the demand side. They're not going to be allowed to fully participate in the system.

MR. GREENLEAF: Demand side is an issue. We touched on it yesterday, I think. It raises some obvious jurisdictional issues, but I think there's opportunities and certainly the RTOs need to take an approach that facilitates the entry and facilitates demand responsiveness. In the context of where we're headed, we think one of the more viable approaches is demand response in the realm or in the context of securing available capacity as part of the available capacity requirement. But it's a complicated issue.

MS. FERNANDEZ: If we were instead to say something into a specific method, would that start creating seams issues? Is a standard congestion pricing method necessary to sort of facilitate trading across the seams?

MR. GREENLEAF: There's tradeoffs. There's a delicate balance that certainly has to be struck there. The fundamental is a system that, as I said, supports real time operations and establishes and is consistent from the real time back into the forward markets. That's a critical feature. Whether that necessitates a standardized pricing approach, I'm not quite sure. I think you want to be flexible in that regard, but what you do want to minimize, to the extent practical, is the seams issues. So the development of common transmission products, like firm transmission rights, certainly is essential.

MR. LaPLANTE: I think it's clearly time for the Commission to mandate LMP. I think we've been having these discussions for four or five years and it seems that every time that someone comes up with an alternative proposal and implements it, problems occur, and they start looking into it and say, oh, gee, maybe LMP is the way to go. I think Texas is seeing it now. The discussions that Steve went through this morning in RTO West led them down the same path. So I think it's fairly clear that there's been a four- or five-year period of experimentation and I think LMP has shown itself to be a theoretically sound way to price and use the transmission system. Obviously there are many academic papers, et cetera, that describe this, and you can present it more than once. I think practitioners have shown that that theory in fact has been borne out and it's probably the most straightforward way to get electricity markets up and going.

CHAIRMAN WOOD: Should the cut over to what I call full bore LMP be triggered by market events, or should it anticipate market events? Because where your markets are, and where ERCOT is now getting is in a different place than MISO, parts of MISO and RTO West and the deep south. I mean, sooner or later it's all LMP. But does the Commission need to put steps in there as to what day one, day two and day three ought to be and what triggers the implementation of day three? Are we just saying we don't care if you're a totally locked up market, go ahead and do LMP today? I mean, what's right? We've gone about as far toward totally unbundled markets as you can get.

MR. LaPLANTE: We're used to a centrally-dispatched single control area where all the trading is essentially financial except at the seams. The west may be much more physical and bilateral in the way they're doing business, so there may be steps that we'd have to get to before the LMP makes sense. You have to have some form of coordinated dispatch for all of the generation and load within the region for the LMP to make sense. If there isn't that central dispatch or central coordination, LMP is difficult to apply.

CHAIRMAN WOOD: Would you do LMP across multiple control areas or does it require a single control area?

MR. LaPLANTE: I think it requires a single economic dispatch. It wouldn't require a single control area, but I think it requires a single economic dispatch.

On the second question, whether LMP is needed to solve seam problems, I think a lot of the nitty gritty details about transactions and transmission scheduling rights may be more important for seams issues than the pricing within a region. So while they're related, I'm not sure that you need to have the exact same markets inside to have good seams between.

MR. KING: I think I would agree that LMP should be the standard. As sort of an example, if you think about driving between New York and Quebec, if I didn't know that the speed limit was metric as opposed to English system, it creates some problems. So if you have different pricing systems in adjacent areas, the market will draw sometimes false conclusions about, for example, how well the transmission system is being used. You may see price differentials that are merely a function of the different pricing regimes being used and not truly reflective of how well or not the transmission is being utilized. So I think certainly within interconnected synchronized areas, you need to have a consistent pricing regime and locational pricing I think is extremely flexible. If there is no congestion, it will solve and you'll have the same price everywhere. And when congestion appears, that will be evident. We were able to implement LMP and we did not have the benefit of a fully functioning state estimator in our system as PJM did. But we were still able to do it using the weighted calculation for the zonal prices that we use in our load zones. It is a flexible system and you don't necessarily have to have all of the infrastructure that some areas have to be able to use it.

MR. SHALABY: I would just add that LMP I think we see it as not just a congestion pricing or congestion management tool, but I encourage that we see it in its full breadth. As financial transmission rights, it's part and parcel of the scheme, transmission scheduling, it's a consistent set of principles that go beyond just congestion pricing, and my only message is that we embrace the entire suite of options there, not just a portion of it. And then sort of do something different that is really a consistent set. I refer to transmission rights, perhaps transmission scheduling, and to what Richard has been mentioning, the load. I'd like to call it not load response but load participation in the marketplace, and I'd like to perhaps remind people here the Ontario market design has significant provisions for load participation in the marketplace. In fact, it's not a market until load has the full capability of participating in the marketplace.

The metering, we put very extensive metering on the wholesale side. You've heard from Chuck yesterday that they are suffering some consequences from less than a full suite of metering on the wholesale side. We have invested heavily in the metering and the metering polling at the instantaneous information on demand everywhere. We think we have the grounds ready for load participation perhaps better than elsewhere. So the message on LMP is that it's got brothers and sisters. Take the whole family.

(Laughter.)

MR. PALIZA: Regarding the LMP used for congestion pricing, and the imbalances, we think that is a sound theory. The question in the midwest is you know the implementation issues associated with LMP, especially since it has been implemented only at this point in time in single control areas such as PJM and New York ISO, New England. We are aware that PJM is expanding that to PJM West. Still, I need to caution that in the case of the midwest, we are talking about a huge territory with particular characteristics that we need to face so that we may be sure that these markets are established successfully. The question about whether LMP requires centralized dispatch, our understanding is that's the case. Our strategy is to do that first and then facing other aspects of LMP, you know, as suitable to the midwest. But in general, we agree that LMP is a good theory to use for congestion pricing imbalances.

MR. WALTON: As we told you this morning, we're headed in the direction of locational pricing. The M is somewhat troubling. People often see it as MC marginal cost, locational marginal cost pricing. When they see the cost, they think incremental fuel cost. That's a disconnect for the hydro operators. And we spent some time this morning talking about the fact that the value of energy at a hydro plant is what it's value will be some time in the future. It's a forward market issue. Since forward market views are quite different in my view of what happens in August of this year and your view will be quite different. From that point of view, there needs to be, when you say LMP, that it's got, as Amir said, a whole suite of other connections to it that go to things like market monitoring, and what you judge as a valid bid, and those sorts of things.

So to the extent that, yes, we're heading in the direction of locational pricing, that's a conclusion we've come to and that it would be settled on a bus by bus basis, those sorts of things, exactly how you implement the bidding strategy and other things, we think we need some space to work in.

MS. FERNANDEZ: It sounds like the main thing is certain clarification that the prices can reflect opportunity costs.

MR. WALTON: I think that's a key clarification because there are so many of these energy limited resources and you've seen the factors and it's such a big issue. There's all those anxieties. There are also people in the group who feel that we should only clear congestion, that we shouldn't seek the global optimum. Now, that's one of the kinks we're still working around trying to get ready to come with firm answers on March 1st. So that's about as far as I can go today.

MR. OTT: Yes. It's time to standardize, yes consistency is important. Probably I'll answer the question on transition. I think as you transition to LMP, if you will, it's obviously important that you have a consistent set of rules and you transition those together so you can take the whole family. But I think as you transition, one of the things we all saw, I believe where we started up, was the market needs to be able to find itself, if you will. So one mistake that could be made when you start the market, an LMP-type market, is you establish a set of financial rights or whatever and they are a long-term right and everybody figures out that they paid the wrong price for them because you're essentially trying to do a five-year lookout on the market that didn't even start yet.

So as you transition, I think rather than transition, the rule set maybe ought to allow the market to define the rights for a couple of months, allow it to find itself and maybe re-auction. So I think the transition is in time rather than in functionality. I think you really need a consistent set. You need the financial rights, the congestion management, everything together, but I think the issue in transition is more one in time.

MR. JONES: I think ERCOT can be an interesting research project along those lines. We're not currently implementing LMP. We had some discussion with some people at lunch who felt like we probably will be at some point but we're not doing it yet. And we have no seams issues so we can work independently of everyone else. I think we will be reopening our congestion negotiations shortly. If we hit the $20 million window on local congestion, it will be interesting to see where we end up. We have a price history without it in the zonal mode, and if in fact it is implemented at some point in the future, we can get pricing information with it. It'll be kind of an interesting comparison.

MR. KELLY: Maybe a quick follow up to Mr.

Paliza. You said yesterday that the MISO would do energy imbalance throughout MISO with 15 minute signals to the control areas and the control areas within the 15 minutes would do the regulation. It strikes me, and I admit I'm guessing here, that that takes you a long way toward being able to do LMP. If you hear the hesitancy in my voice, maybe you have the same hesitancy of would it work in practice. Like Steve Walton says, I want to test drive it first. But do you see any conflict between LMP and the system you described yesterday for balancing globally and regulating locally?

MR. PALIZA: First of all, let me just clarify that our initial intent is to have a shorter interval for the security constrained dispatch. We are shooting for five or six minutes; whether that's feasible, that's what we need to discuss as an implementation issue.

Second, what I mentioned yesterday is that, as a first step, we will try to centralize the dispatch while leaving the regulation with the control areas, but that is only an interim type of solution. Eventually we want to set up regulation markets the same with the reserves. So, yes, I think in general our strategy is facing you know the LMP methodology with the financial transmission rights and all the other aspects that I presented yesterday, you know, demanding that we take only a number of steps each time and make sure that they work, so that we can take the next steps and so forth, rather than trying to do everything at once and risking complete failure.

Let me just clarify this. I talked about the MISO yesterday and the number of control areas when it comes to the network model, which as you have heard before is a requirement for the LMP, the next step in the security constraint dispatch.

In the case of the midwest, you know, the network model is for the entire midwest region. It's more than 30,000 buses. That has not been solved yet. That would be unique, and we are discussing already how that could happen, how would that be feasible, whether we need to start thinking about new approaches in getting a snapshot of the system in real time, rather than using the standard method that the vendors have now. But that's only one aspect to show you the kind of magnitude of issues that we will be dealing with in implementing this in the MISO.

MR. O'NEILL: Could I go back to one of Steve's comments?

MR. WALTON: Which one?

(Laughter.)

MR. O'NEILL: The Commission has recognized that the marginal cost of hydro is not the running cost or essentially zero, but it is the opportunity cost. Is that clear to the people in RTO West?

MR. WALTON: I don't think when the staff paper came out, it was all that clear. There's some other things that have unsettled folks and that's things like the market monitoring standards, the new tests and so on that have unsettled people with regard to what the situation is. I think that by and large, that's what's unsettling to folks and why there's some anxiety. The issue, as Roberto just told us, the issue of how fast you can get there and learning how to make these things work, shifting gears, starting new systems and software, those are all anxieties as well. But certainly the question, the issue of what marginal cost is and whether marginal cost includes the opportunity cost, you know, every time there's something that comes up that suggests that that might not be, the people say I told you that's what they really meant, they're just trying to fake you out. You say, no, no, I don't think so, and then there's this debate that goes back and forth.

That is the reason we keep saying because there is an anxiety with regard to that.

MR. O'NEILL: Internally among Staff, we recognize that there's a significant opportunity cost issue in hydro. I think the Commission in some of its orders has recognized that issue also. So, I mean, if there's something we need to do to clarify that, to move forward --

MR. WALTON: These exchanges have to establish that. That's the value of these exchanges. Certainly we keep hitting this nail back it's the one that we care about, and it looks bent to us, so we keep pounding on it, you know. I spent my whole life straightening out nails for my dad. We just keep beating on that one issue because it does matter. It's a key issue and raises lots of concerns with folks. One of the resistances to going to this nodal approach was in fact that concern.

MR. O'NEILL: When I straighten out nails, I usually hit my finger.

(Laughter.)

MS. FERNANDEZ: Let's get back in terms of the energy market. It seems to me that the major issue I was hearing, or differences, there seems to be general recognition and agreement on a real time market. The issue seems to be with the day-ahead market, whether or not there should be a formal day-ahead market, where in effect people don't have to have balanced schedules. Or you should have a system where there are balanced schedules submitted for the day-ahead market.

I guess the basic question there is is this a best practice to standardize on one or the other? Would it create a lack of standardization in terms of allowing one organization to require balanced schedules, other organizations not to? Would that create seams problems and sort of harm trade among the regions?

MR. SHALABY: I separate in my mind the issues of balanced schedules from the day-ahead market. Do you imply that they go hand-in-hand? You could have a day-ahead market that doesn't require balanced schedules, as an example.

MS. FERNANDEZ: Usually if you're running a day-ahead market, a lot of people procure supplies through it.

MR. MEAD: Let me just tie in, I'd be interested in hearing how you could have a balanced schedule requirement and a day-ahead energy market at the same time because in my view, the day-ahead energy market allows a supplier who hasn't balanced itself with a load, or a load who hasn't balanced itself with a supplier to come someplace and find the other part of the transaction. If people are required to come to the RTO with a balanced schedule, I don't see what else the market is doing.

MR. SHALABY: You're presenting the other side if there is one, maybe you don't need the other. So the question maybe supports my question. That is, do they have to go hand-in-hand or can they be separate.

MS. FERNANDEZ: I perceive them as going hand-in-hand.

MR. SHALABY: I thought the PJM market, as described yesterday, and maybe Andy can expand on that, as a day-ahead set of transactions but no necessity for separating balanced schedules. Is that right?

MR. OTT: That's right.

MR. WALTON: What triggers this is that we talked about balanced schedules. I think that's what you're really asking about.

MS. FERNANDEZ: There also is an ERCOT.

MR. WALTON: The issue of an unbalanced schedule and the ability to submit unbalanced schedules certainly became a sore point in 2001 when in California there were people who were substantially short and when people went short, it created these problems. So the concern of a number of parties is that parties ought to have or ought to bring their resources to the party. And what we are planning for the day-ahead process is a congestion clearing market. In other words, if people schedule, and there is no congestion, we're done. If people schedule and there's congestion, then we would use the bids they have to clear that congestion at minimal cost to do that congestion and we're done. That's the starting point from which we work.

As I said, the idea of showing up short by half their load, and their load is 500 megawatts or 1000 megawatts doesn't -- as they think about building what has never existed, that's not been acceptable to most of the parties.

MR. O'NEILL: Steve, doesn't California have a balanced schedule requirement?

MR. WALTON: Steve Greenleaf could probably answer that.

MR. GREENLEAF: We certainly do right now. That's right.

MR. O'NEILL: You've always had one?

MR. GREENLEAF: That's right.

MR. WALTON: I understand. I'm just telling you I'm bringing the message, you know, shoot the messenger if you want.

(Laughter.)

MR. O'NEILL: I didn't bring my heat.

(Laughter.)

MR. WALTON: The other issue on this is everybody who has a red tie -- I used to sing in a quartet, the guy with the red tie always insisted we wear red ties the next day because he already owned one.

(Laughter.)

MR. MEAD: Is the main difficulty with the day-ahead market the expense of software?

MR. WALTON: No. There is a firm belief in the northwest that there has been an active forward market and an active hourly market in energy at Cobb and at Mid-C for a long time. It doesn't need to be supplemented by the RTO stepping and putting itself in the middle of that market. That's what the concern has been, that people can bring their energy in. I'm just telling you what the message is, okay? But that's the concern.

CHAIRMAN WOOD: For those that do not have a balanced schedule requirement in advance of the delivery hour, why wouldn't you want to have one, other than the red tie issue?

MR. OTT: I think the point we discussed some yesterday too the point is flexibility. You need to provide the participant with the ability to react to the market with the least amount of barriers. If you have a balanced schedule requirement in one area, and you don't have it in the other, that may cause difficulties in getting trade between the two areas because you have to do something special in the other. You can use a thousand examples. A wind turbine has more wind today, he wants to dump energy in the market but he can't. There's a lot of restrictions where the market could take advantage of efficiencies but it's not able to because of some requirement of a balanced schedule.

I think the idea of flexibility and letting the market incentive take over is really where I would throw it. It's more the fact that I think it helps support the depth and liquidity by allowing the least amount of errors.

COMMISSIONER MASSEY: If one of the principles is that the market that you overlay the way the system operates in real time ought to support that real time system operation to the maximum extent possible. Does a balanced schedule requirement, is it consistent with that philosophy or inconsistent with it?

MR. GREENLEAF: I don't think it's necessarily inconsistent. It's important to remember the context. In California, the SDI has some of the balanced schedule requirement but that went hand-in-hand with the existence of the California Power Exchange which provided people an opportunity to purchase and shape their purchases in the spot market. That feature of course facilitated, it became problematic with the ISO I think with the demise of the California Power Exchange, that there wasn't that opportunity to shape.

Yes, there has been and there continues to be today bilateral markets in California. But it did seem at least essential for purposes of the California load serving entities to have that opportunity to do incremental procurements in the spot market of the day-ahead, so I think it does, that opportunity is necessary really to shape load and to closely match load, so that going into real time, you have secured resources necessary to serve anticipated load.

MR. O'NEILL: Suppose a lot of people in California got religion and put photovoltaic's on their rooftops? How do you accommodate the photovoltaics? Do they have to schedule into the market?

MR. GREENLEAF: I don't know the answer to that, Dick. Certainly that's something we're going to have to going forward, as far as any kind of demand response or facilitation of alternative resources, you need to design for flexibility to accommodate it.

MR. O'NEILL: The two interesting sources, wind and photovoltaics, are two sources where balanced schedules can be really problematic.

MR. GREENLEAF: You can establish rules that attempt to accommodate the intermittent resources, but you're right. It poses challenges for them.

MR. JONES: I might comment. ERCOT has a growing amount of wind energy. We have several hundred megawatts already. It has first priority. It runs when it's available. The QSEs that host that, it's part of their schedule. They just have to vary their other generation around that wind energy so that they basically follow their schedules.

There's not enough photovoltaic probably to be a real issue on those lines at this time. But one consideration on unbalanced schedules that we sort of experienced in our area, and we're small. We're not as large obviously as the other two interconnects by a large amount.

But since we're the single point of control, we have to make sure we have the tools at our disposal that we can control the frequency for reliability and on instances where some of our participants don't do a good job of following our schedule or matching their schedule, we had to just about expand our ancillary services like regulation and so forth to make sure we had the reliability.

So we've been forced to carry a pretty large amount of ancillary service. So the savings that you get out of one area may actually be spent in another area to ensure that you continue to have good operations.

MR. O'NEILL: It's interesting. Because the Northeast ISOs don't have those requirements, and yet don't seem to have those problems. Why is in one case?

MR. O'NEILL: I think if somebody goes short, okay, then the whole market's short. The price goes up. Their incentive is to fix it because they're getting killed on the market. Obviously, regulation will help you get over the hump, but the point is, it corrects itself.

In other words, the spot market is there. The price is there. You can see it. If the whole market goes short and you're short, you're in trouble, because the price has gone up. So it corrects itself. I think the balanced versus unbalanced, it's almost like a leap of faith thing.

When we first went into the market, you had to give an hour or 90-minute notice to change anything. We honestly did have a conservative approach. Now it's 20 minutes. The reason is because we've seen it work. It is difficult to have the leap of faith, and maybe it's more that than anything.

MR. O'NEILL: Are you saying allowing unbalanced schedules meaning having faith in the market?

MR. OTT: Yes.

(Laughter.)

CHAIRMAN WOOD: Was there a penalty for being out of balance just buying out of the balancing market, right?

MR. JONES: That's the primary. The other is uninstructed deviation when you overgenerate basically in ERCOT. Part of it, Dick, too, is in the size. If we use a nuclear plant, 1,250 megawatts, we'll go to 59.65, 67 in our frequency. If we use a nuclear plant 1,250 megawatts, we'll go to 59.65, 67 in our frequency. If you ever saw the Eastern Interconnect, they'd be panicked.

Conversely, we've had plants say combined cycle -- excuse me, combustion turbine -- which can come on very rapidly. We've seen, say, a 650 megawatt plant come on unexpectedly out of schedule, and our frequency went over

60.1 before we could get other generation down. So a lot of that is based on size and characteristics of the interconnect. We're sort of a special consideration in that sense, if you want to talk about special needs of a region.

MR. O'NEILL: In any case, if a nuclear unit goes down, schedules go out of balance. So you violated the balanced schedule requirement.

MR. JONES: It's just a matter of how many recovery tools you keep in your hip pocket.

MR. O'NEILL: I agree. You have to have the recovery tools. There's no doubt about it.

MS. FERNANDEZ: Maybe we should move on to the transmission, because I see we're getting -- I was hoping to end around 4:30.

In terms of transmission, can I say this, that there's a consensus that the rates should be financial? All right. It seems like the issues that we've had some differences, and I was wondering if this is one where we talked about standardization, best practices, is sort of how the financial rights are assigned or allocated if they should be done through auctions or assigned. Do people have opinions on that? Is that something the Commission should standardize or should allow deviations?

MR. WALTON: On that one, thee needs to be some deviation ability there. The reason is because of this contract conversions issue we talked about earlier. To try and force everyone to go to auctions and take the revenues, that's problematic even if it was the right thing to do, it's problematic on a short-term basis.

When these markets start, there's absolutely no track record as to what value the transmission option or obligatio is going to be. So at least at the very minimum, you need to have the track record. And I think what Andy said is you need short windows to stretch that out if that's the direction you're going.

But the other issue here, and the one we talked about this morning when we mentioned our approach to cataloging rights is the notion that we have large numbers of existing contracts in order for us to bring along the federal system, which is an enormous part of the system. That we have to deal with that issue of conversions.

And so if we were to force everyone over to an auction, for instance, that's a nonstarter for a very large number of our parties.

MR. PALIZA: I will support that view that we need to have some flexibility in this regard. This is one of the big topics in the Midwest, and I think it's a transition issue. We are shooting for a full auction. However, parties don't feel comfortable on day two when we put together this system to have a full auction of the rights. They feel that needs to be a time period for the location assigning these rights and then, you know, transitioning into a full auction.

There are a lot of details of how that will happen and who gets what. But that's an important issue to have some flexibility.

MR. GREENLEAF: I can just offer that from the start of our FTRs through an auction mechanism, it was supported by most of the market participants. In fact, there's a strong preference for that in California because of the ability of the nonincumbents to gain access and to gain those FTRs.

However, I don't necessarily think that prescribes alternative approaches. For example, I think RTO West is establishing rules that are attempting to create incentives for an active secondary trading of those rights. That's certainly a necessary way to go, and it gives everybody an option or an opportunity to procure the rights they think they need or they want.

MR. KING: I think in our experience, we beat our brains trying to think of every other way to do it besides having an auction. Finally we took Bill Hogan's advice and said we'll just have an auction. We found that it's worked very well for us. But I do appreciate the difficulty in getting to that point, having to deal with existing contracts.

There does need to be flexibility to avoid parties from being harmed simply because they entered into a particular transaction arrangement well before we knew the world was going to deregulate.

I think we fully support auctions and perhaps maybe there needs to be some guidelines, maybe something less than rules, but if you are going to have an auction, auctions maybe should adhere to certain guidelines but allow flexibility for other mechanisms of allocating the financial rights as you need to do to work your way through this transition.

MR. MEAD: With regard to the issue of parties that have existing rights, two I guess related questions. My understanding is that in some instances the existing rights may carry with them certain timing and scheduling features that aren't the same as the rest of the RTOs timing and scheduling, scheduling an hour ahead versus some other point, and there may be some other technical features.

If existing rights are allowed to be retained by existing customers, are there some features that nevertheless need to be modified to make them more consistent with the way the rest of the RTO operates?

MR. KING: I'd like to just take a quick stab at that. I think where it makes a difference is where such contracts span between RTOs. I think that where it creates seams issues is where these transactions may be handled differently. As long as they're handled consistently, I think you can deal. You know, you'll find that each transaction ends up being unique.

It's hard to put them in a box, but I think that on a transaction-by-transaction basis, our experience has been that we went through a process of giving the parties to these transactions the option of either converting to TCCs or retaining what we termed grandfathered rights. And there were differences in how they treated congestion in relation to transactions that were discovered against them.

Once that decision is made going forward, we treat those transactions a certain way. But again, where they span multiple control areas, there has to be some consistency there. If you're doing a unit commitment in one area and you don't include the transaction, you may find that operationally you won't be able to support the transaction in real time because you haven't committed resources in the right area.

Again, the skin of the onion as you peel down and look at the implementation details, that's where some of these seams issues evolve. I think consistency is important. Allow flexibility so that you can handle the variety of types of transactions that are already in play.

But I think you need to treat them consistently between areas, the areas they span.

MR. OTT: I think the contract would have some timing implications that would be at odds with the market. If there's a large volume, I think it could be problematic. The point of converting these contracts, probably the way to do it is to incent the conversion. If you were to try to get them over, I think you should be very cautious about just converting large quantities of these.

I know in our area we didn't really have the issues, so I probably can't speak to it. But from the market functioning point of view, it would be similar to like physical transmission contract type things inside the market. Again, the more you add to those, the more it strangles the market, and it gets away from the efficiency point, and then everybody loses.

MR. WALTON: In the proposal that we're bringing forward that's under development, everyone schedules on the same basis and the existing rights are being actually converted to something different. They're not being kept as the old physical rights because they no longer have the blocking capability. It's not like you can withdraw the capacity from the system, derate the system and get phantom congestion.

What's happening is those rights can be put in a catalogue. You can think of it if you will as a de facto pool of these rights that are being held in common by the set. The reason for doing that is that the sum of the parts is greater than the whole available by a substantial amount. When we try to add up all the pieces as separate individual elements and all the directional things that happen is as people swing energy back and forth day and night, when you added up the whole package you just had more than you could award.

The way to get around that was to collapse them into one pool of rights and have everybody after they've scheduled. Then you can release the surplus.

You also had those in this pool even on a monthly release or something else. You could guess how much would be available. But the parties weren't in a position to release the optionality that they had built into those contracts in terms of delivery points, not just timing, but also multiple delivery points, multiple directions.

That's the reason we pulled them all into the central group and then said well, they're going to settle also the same way because they'll be both like the rights. The catalogue rights are also credits against the congestion costs, and calculated congestion costs would be assigned to these. It would just be credited away. You still get the transparency. You still see the price signal. You still don't know what the CTRs are worth, which goes to the incentive question.

People, after this has been running for a while, say I'd be better off if I took my point-to-point contracts and converted them, because I can then market the secondary capacity easily where I can't do it today. In some cases in the existing contracts, they can't remarket them at all. So we're working on building a set of incentives or trying to get some incentives that cause people to think, oh, this is a good idea. I will convert to FTOs and pull my stuff out of the catalogue rights. The catalogue rights are also limited to the original footprint that you have on the delivery point.

So if you want to build a delivery point, there's a reason to desire to convert.

MR. GREENLEAF: I think our experience clearly indicates you want to conform all the ETCs, get everyone on the same scheduling timeline. There's different ways you can do that. Certainly the incentive approach is probably the preferable approach, converting those ETCs over to FTRs. But there's also probably other ways to deal with it.

For example, as I said earlier we're examining changes to our hour ahead scheduling timeline to bring it a little bit closer to real time in order to accommodate some of the special needs of the vertically integrated utilities who want a load follow through the day.

So whereas today we close our hour ahead markets two hours prior to the trading hour, the operating hour, moving that closer accommodates them to a greater extent and provides incentives for them perhaps to convert over. So there's different ways, and it really has to be multi-dimensional I think really to accommodate them.

MS. FERNANDEZ: In terms of the actual financial, the various hedging mechanisms, the FTRs, whatever name we finally come up with, we had some discussion in terms of point-to-point and flowgate and options and obligations. I guess the question is, can these all sort of coexist? Is that something the Commission needs to standardize?

I think it's probably essential that there be some hedging rights in any of the systems. But in terms of if the Commission were to say you must offer obligations, you may offer options. Is that something that could be explored, or you must offer point-to-point rights, you may offer flowgate options? Is that something where standardization should be required or something where it still needs some development and perhaps some innovation?

MR. OTT: I think probably, especially in the point of options, I think we are still trying to develop what I would call the production grade software, at least in our case, to see how they'll price out. So as far as option versus obligation at this point, at least from my perspective, we're still probably trying to struggle through that. But very definitely, the suite that we have of obligations, point-to-point or flowgate, an option point-to-point or flowgate, I think all four should be sort of in the suite of possibilities.

I think you definitely need financial rights. Probably they need to take at least one of these ways. It may be a point of future standardization. Just because it's still in my own mind, I'm not sure if the market itself will be able to, how shall I say, live with the price of options as they may exist to require them and them only.

In other words, it would probably be a mistake to say that you only can have one of those and not others. It may be far enough to go to say that you have at least one of them. I don't know what the rest of you feel like.

MR. WALTON: I'd agree with that, although there are reasons we don't like the obligation situation because of the nature of the system. And so to prescribe that we had to have them even if they were both allowed, you know, but to say that we had to have financial rights would be acceptable, and we'd pick our brand.

MR. GREENLEAF: I think they key on this issue is designing for flexibility. And again, Andy mentioned that yesterday. You want to be able to accommodate what the market desires really. And we put the question out in some of our focus group discussions over the past week. Some of the comments we got back were, we want them both. We want potential obligations and options offered on a point-to-point, point-to-hub, hub-to-point, whatever basis. So design for flexibility.

There are inherent tradeoffs, but at least our operations people tell me that you can achieve simultaneous feasibility on all by offering both.

MR. OTT: One thing I'd add is, probably the requirement you're looking for is you have to be able to hedge to any point. In other words, you have to be able to hedge to a hub and to the zones, in other words, more of the standardization is you must be able to have a financial product all the places and be able to have complete hedging as opposed to what specific type. That's probably where we're at.

MR. KELLY: A question for anybody, but I'll direct it at Andy. You said something yesterday, if I recall, to the effect that your market design maybe had ten elements and it doesn't, it's not good enough to get nine right and one wrong because that's where the things will go wrong because they have to work in concert.

MR. OTT: Correct.

MR. KELLY: As I was listening to this

discussion, it was occurring to me, well, maybe you have ten elements and they all have to be defined. YOu can't leave one flexible and maybe in the Northwest they have another ten elements, and those ten work together. But if there were a standard market design that let's say had nine elements, maybe you couldn't leave the tenth one optional. Maybe that's a comment rather than a question. If there's any reply to that, please feel free.

MR. OTT: I think very definitely in the standardization mode, if you're going to get into a level of detail below where we're talking today, I think very definitely there are certain things that matter.

I'll pick on the same thing I'd done earlier. If you have an hourly bidding structure, you probably need some type of performance penalty to go with it because of the ability to change. When you add that kind of ability or flexibility, if you will, to being able to change and bid hourly, then you have a lot more stress on the control systems.

The system can only move out of generation so quickly. So if generators can have step changes in their economic offer data, you could actually have all the cheaper generators suddenly change their price in one hour to go higher, and that could cause a huge change.

PJM, since we don't have that and we have the way we price energy, for instance, everything's incentive driven. So we don't have to impose penalties because of the structure. But if we could change one thing like hourly bidding, then we would have to take the rest of it and put penalty structures in, because the market wouldn't be able to handle it.

That's where I was in that kind of thing. It sort of holds together as one group, and if you make one change, you just have to make sure you understand it, if that's what you meant.

MR. KELLY: Yes. Wouldn't these FTR obligations versus options be an element that couldn't be changed unilaterally without changing other complementary parts of the market design?

MR. OTT: I don't think that it would fall into the same category. I think very definitely, market participants will want the ability to have both options and obligations because there are certain -- if you're serving physical load, you may just want to say, no matter what the price difference is, I want it covered. I don't want to worry, and I don't want to pay an extra price for it, and I don't want to pay an option price, because I'm just risk averse.

I want to be indifferent to spot. I want to take my generator, my loop. I'm not worried if it's positive or negative. You very definitely need that type of participation because you have a class of customers who want it. By the same token, the people who are trading through are the people who are going to want the option types, because they don't want the risk of the downside.

So I think in this world, when you're in the financial rights world, I think it's less. As long as you have a set of financial rights that hedge you against the uncertainty of your real time congestion or day ahead congestion, I think now you're back to say what the participants need. Now you go to the stakeholders.

It's not one of those categories where I think it would break other things.

MR. KELLY: One last follow up on this. It seems to me that knowing whether you can rely on counterflow is important. That is, if the prevailing power flow is from you toward me and I have a right to send power from me to you, which reduces the loading on the grid, that allows the system operator to sell extra flow from me to you to balance my counterflow.

If I have a right to send that and choose not to, that affects what the system operator can do in terms of relying on or not relying on me to use the right I have.

MR. OTT: Absolutely.

MR. KELLY: Isn't that a very important element of much of the congestion management system that has to be tied in with everything else to develop a system that works?

MR. OTT: Yes it is. But I think the issue of counterflow, if you're in the transmission rights world, the FTR world, when you actually calculate the price of an option, if you would go to the option the price includes -- the price of an option will always be higher or equal to the price of an obligation on the same path.

The extra amount, which I personally think will be very large, actually reflects the price of buying up all that counterflow reservation so no one else can take it. So essentially what you're doing is you're implicitly buying that up. That's what puts the extra premium on an option price.

Let me make sure I pronounce right. But the point would be in that structure, if you have that in your feasibility study, that will take care of the revenue adequacy issue, so you'll be okay. The fact when you're in the energy market and you have counterflow of course you would pay the counterflow, the difference in price going the other way. But that's inside the dispatch. Everything is internally consistent. You're okay over there too because the fundamental separation between the financial and the physical market, if you make the changeover in the financial market, as long as you're consistent there, you're fine.

MR. SHALABY: Kevin, I know you're trying to converge and focus. At the risk of maybe expanding the scope of your question, you're asking about internal consistency between design elements within the wholesale market.

I believe without disturbing anyone more than they need to, that the notion of consistency between the wholesale market and other aspects of the electricity market, the retail sector, the nature of the retail sector, for example, the powers of the entities within it, the regulatory structure in the provence or the state, the nature of the resources, the adequacy of transmission, enlarging the scope of the question to say that wholesale market elements have to work well together with other aspects of the electricity sector and the authorities resident in different agencies and on bundling.

Just to leave it with you that the internal consistency goes beyond the wholesale market rules. That may be more evident in a jurisdiction that's very different than most of the ones you deal with. But it may in fact be in the jurisdictions you deal with as well.

MS. FERNANDEZ: Let's move on to the reserves issue. That seems to be an area where there's a lot of calls for flexibility. I'd like to explore how much that should be or could be standardized. Operating reserves.

We're not talking about ICAP today.

Are there specific products in terms of, you know, it's like the regulation spinning reserves, that there could be separate markets for those and not others? Or is it something where there should be more flexibility, depending on the various NERC regions and requirements?

MR. OTT: I guess I can -- yesterday I mentioned I think most areas, and I'll leave it to others to talk -- but regulation and spinning reserve are sort of a standard that you need when you're operating for reliability.

Some areas may need other services like spin or 30 minute. And perhaps they don't. But I think at least at a minimum, I think those two, having separate markets for those, at least separate real time markets for those, is probably something that most of us will agree to.

From my perspective, I think, again, as I expressed the anxiety yesterday, I think going all the way to say that you need forward markets for these since we've had so much trouble in that area where the ancillary -- actually they distort the real market you're looking for, which is the energy. I think probably I would rather not make that a requirement. I'll leave it to the rest.

MR. WALTON: We're still working in this area, so I think it's premature to nail it down, because there's enough uncertainty as to exactly how we ought to put this together and how to nail those issues down. And some people there should be regulation after regulation down, and all other sorts of things. So I think it's not ripe for standardization.

MR. KING: I think to the extent that there is any standardization, it needs to track the NERC requirements. My understanding is that NERC is moving towards a 15-minute requirement. And then that may foster the need for a 15-minute product where we have 10-minute products now. Again, that would call for being flexible and allowing this area to evolve.

I think it's important that we not constrain any areas from setting up markets if they feel that that will enhance the operability and reliability of the system and the visibility of the constraints related to the reserves; for example, in regulations having markets for them and having the markets tied in with the energy market.

I don't consider that a distortion. I consider that the handling of just another set of constraints in the problem, and I think it needs to be visible because when there are shortages in reserves, you've got problems, and the prices in the market should reflect those problems so that resources can be brought to bear to solve those problems.

We'd like to have incentives that encourage investors to build quick start plants in areas where we're constrained. That's certainly not something we want to discourage. So we think the flexibility should be there for those areas where they rely on those services, can have the markets, can have the proper incentives to encourage those markets to be sustained and hopefully grow.

Our experience has been with our markets, we've had a very good response in our reports, and we show the amount of capacity that's being offered into the ancillary service markets. It's substantially more than we actually need. So the response to those incentives has been very, very good.

MR. LaPLANTE: Providing for regulation market and a spinning market makes sense. I'm not sure we're far enough along to actually mandate a specific design for those two types of markets. PJM, New York and New England have three different regulation market designs in place. I think they've all worked reasonably well. And the spinning reserve markets are different as well. So I'm not sure that we have one single ancillary service design yet that it makes sense to standardize on.

But those two products I think are universal products that need to be part of a working market. And the other reserves, offline reserves, I think an area for innovation and experimentation that I think should be permitted.

MR. KELLY: Dave, does having the same requirement but different market designs create seams issues or inhibit your neighbors from providing you with reserves?

MR. LaPLANTE: There's a lot of question there because one of the things that have defined a control area or an RTO to date has really been providing its own ancillary services.

We really don't have provisions in operations or in the markets to, say, buy reserves from New York or buy regulation from New York. We might do it by expanding the regulation area, but I don't think we'll really see trading of ancillary services between control areas.

MR. GREENLEAF: I would concur in many of the statements made. I do think it's a potential seams issue and I think I do want to strive for some compatibility, if not the development of a common product. But that would have to be on a regional basis.

Obviously, the reliability-related services, the regulation and the operating reserves I think need to be tailored based on the NERC regional practices or standards that are established. That can vary. I don't know if does vary, but it could vary, so you need to allow for that flexibility.

But I do think it's a potential seams issue, so you do want to strive for commonality and develop common products. California, for example, does provide for and allow for operating reserves outside the control area. It limits that because of the locational dispersion requirements, but nonetheless it does allow for that. And I think you want to facilitate that. I think those are viable markets and you want to provide for the opportunity to provide those on a larger regional basis.

MS. FERNANDEZ: If you have a common product but the flexibility, for example, with the regulations, the flexibility is in how that product is procured, whether through a separate market or through sort of the energy bid process, is that the type of flexibility that you're looking for? Anyone?

MR. OTT: I think the flexibility they're asking for or we're asking for in general is that I think we all agree that you need to procure, the RTO needs to procure these services to maintain reliability in real time. To some extent, they may or may not need to schedule forward.

There's a variety of ways to schedule it forward. In our case, we have the ICAP requirement, et cetera. In the other cases, you actually lock it in financially forward. But I think when you get into the real time world, the actual procurement of the service and the fact that you need a regulation, quote, "market in real time" with a price that's separate from the energy price and that actually shows the difference in that product, it's probably something you can standardize.

Meaning that if you have a real time market that is a separate market with separate offers, if you will, for that, I think we're agreeing on something like that. It's the can you, how do you do it further out, is maybe the question.

In the case of having it causing seams problems or not, I think probably the only danger here since these are in fact, and MISO I'm assuming as we are in PJM West will have one dispatch across the regional market, you have actually separate ancillary markets within the control areas because you're actually controlling. So I think you'll see those kind of things. And I'm not sure if it'll develop a seam, if you will. I think the only time it could develop a seam is if the design of the ancillary market actually creates a timing issue for the energy market, meaning it creates some boundary.

Again, whether it's the scheduling boundary of the control areas or whatever, that's probably the only danger I would see. I don't know if that answers your question. I've rambled enough.

MR. O'NEILL: Can I follow that on a little bit?

Steve says you can get reserves outside the control area. In New York, we obviously have a constraint where western reserves don't mean a whole lot to the eastern side of the market. Have people given very much consideration as we move into a more financial rights market of how those reserves that are not essentially right next to the market are going to have to get into the transmission market? Because certainly if there's a constraint, reserves on one side of the constraint don't do very much good to serve the reserves on the other side of the constraint.

Have we thought through how we're going to deal with that, in a market context I mean? Sort of the simple answer is, distant reserves need to set aside transmission in order to become viable, but I haven't heard lots of thought about how to do that.

MR. KING: I think there's a tradeoff there. Even something as fundamental as reserves -- you know, when you're transmission-limited, obviously you can't get the reserves to where the deficit is, where you lose the key generators that they don't do you any good.

Certainly, one can operate their system such that they can always get the reserves to where they need. But you would have to reduce the transfer capability greatly to allow yourself the huge operating margin to have that occur.

So now you'll have a societal cost, a less-than-optimal operation of the system.

So when we're asking these questions, I think the tradeoff that we're talking about is, you know, how much flexibility do we want in these markets compared with how extensively do we want to use the transmission system? We want to get as much out of the transmission system as possible, operate as close to the limit. Then that means you need to have very precise knowledge of where the reserves are, et cetera.

If you care not to do that, if you prefer just to be able to have the reserves anywhere in the system and not have occasional constraints, then you'll find you have to reserve the transfer capability across the system where you're limited to allow that room. So when you do lose the big unit in the constrained area, the reserves can flow.

So it's an economic tradeoff. The operators will always figure out -- give them the problem. They'll always be able to figure out how to operate the system reliably. It's just the question being, at what price.

MR. WALTON: And the issue of locational reserves is an open question. In the west, through the WSCC -- soon to be WECC -- it's looking at the standard, where those reserves ought to be carried and where they ought to be, and what the level should be. The level is probably higher than it needs to be. But on the other hand, it probably needs to be distributed more widely.

So the reliability standard, at least in the west, is under consideration there as to what the standard really ought to be. And that is going to affect how we figure this out in the long run.

MR. LA PLANTE: I think in traditional reserve planning, the need for reserves and the locational aspects of reserves have been sort of layered on top of the energy market. In making the assumption, as Chuck was pointing out, you want to worry about energy first. And if you have to put some extra reserves on somewhere, or locate some gas turbines somewhere to support that, that's what you do, rather than conservatively operate the transmission system to support the reserves.

There's actually an activity ongoing now in the MPCC region to review operating reserves and see if they can be reduced if the use of operating reserves is coordinated better amongst the regions. There's a similar effort ongoing in the AGC market as well. So there are some regional efforts to improve AGC and reserve markets.

MR. SHALABY: I sense this could be a good example of what Kevin was alluding to -- the location of reserves and the component for the market design that has to do with reliability must-run provisions. They can be complimentary or you can ease up on one if you toughen up on the other. These are two things that perhaps have a link. If you have the must-run provisions, you could sleep a little easier about the location of reserves.

Just another point, and in support of the notion of standardizing the products, but not the way of procuring or administering them, that may be a fruitful route to follow.

MR. OTT: I don't know if we talked -- in energy we have the ability to supply from self-supply, bilateral or spot in the three ancillary markets. I believe that same ability to sort of be indifferent may be a form of standard in the sense you have to be able to self-supply or self-schedule, or use the spot. That may be some point of agreement we have. We have that on energy, I think.

So I think we don't really on our table do that. But that's an area.

MR. PALIZA: In the case of the Midwest ISO, where you are dealing with the NERC reliability councils -- MAPP, MAIN, SPP and ERCA -- right now we are working through the issues: sales regulation, location of reserves, placement, and how they would be deployed, and how the system is going to be reserved for delivering these products.

We are currently working through these issues from that standpoint. I think it would be premature to try to standardize these at this time.

MR. KELLY: Clarification to Andy: the Staff paper proposed that there be an operating reserves market. I take it PJM would object to that -- is that correct -- saying, require us to have a regulation and spinning reserve market, but don't require us to have the market we're in the process of giving up.

Is that a good conclusion?

MR. OTT: I wouldn't know that I would strenuously object, if that's your question. If you look at our ICAP requirements, and the fact that people use the ICAP and the rules applying to that, there's a certain revenue stream that generators get from the ICAP.

If you think about PJM West, we call it an ACAP or available capacity market, which is a shorter-term-type capacity market, which may be getting more towards an operating reserve type. So to say we, PJM, would strenuously object to that I think would be too strong.

MR. KELLY: You'd prefer we didn't do it?

MR. OTT: Yes. I think the dynamic that we have today seems to be working okay. But I don't think we feel strongly enough that if you did do it that it would harm what we're doing.

MS. FERNANDEZ: Let's see if we can move on and try to get out of here early.

Market power mitigation. It's not something we've talked about an awful lot over the last couple of days. A number of the existing ISOs do have provisions for reliability, must-run. Is that something that should be factored into the standard market design?

MR. LA PLANTE: Yes.

(Laughter.)

MR. LA PLANTE: I think it's a challenging area. California went through a lot of work to get there. New England now is trying to standardize on contracts and agreements that were ad hoc in the past, and we're having a difficult time doing it. Generator owners that bought generators in congested areas that only run for congestion have very different ideas about what costs they should recover. They're the people that are paying those costs.

(Laughter.)

MR. LA PLANTE: I think that's really an issue that only the Commission can decide that sort of issue. It puts the ISOs and the RTOs in a difficult position to resolve those issues. So that's something that probably would benefit from standardization.

MR. KING: I would just add that I think providing market monitoring capability with as many tools and flexibility as possible to deal with a variety of situations -- you know, the idea of these contracts falls in line with that, and so there should be some provision for allowing those types of contracts to occur.

MR. GREENLEAF: I would concur. I think you do certainly need to allow for the flexibility on a case-by-case basis. There's going to be a need for that.

One of the issues we're examining right now is the interplay between our existing RMR and where we're headed with the ACAP requirement. The question before us, and one of the things we're considering is, can you build into the ACAP requirement a locational aspect to that, such that you effectively address the local market power issues and the ACAP all in one.

Procurement. It's a challenging question, and we really haven't thought through it yet. But it's one of the issues we're intending on hopefully addressing.

MR. WALTON: We're not particular fans of the must-run. We don't think we need that. But the whole issue of market mitigation and the other issues, the details are yet to be worked out.

We're talking about a common market honoring operation that reaches across the whole west as part of the one-market vision that we have. At least for the northwest, we don't see a reliability must-run as a requirement.

MR. OTT: I probably have something to say now.

I think in this area you certainly need to deal with the issue of localized market power. You have these nodal pricing markets. You have areas of the market that are restricted by transmission. There's only a few generators that can do it. Again, absent load response -- we don't have a load response yet, so I think you need to get there.

But the one thing, in PJM we have the alternative essentially that the generators have. He has three alternatives: the cost plus 10 percent, the historic market value, or the negotiated rate between PJM and the entity. I think the issue of having certain generators have restrictions, environmental restrictions or whatever -- it may be a cost plus 10. I think the contracts you can have to get the reliability must-run must reflect the reality of the situation such that you don't close down the generator that you vitally need to make it reliable.

MR. KELLY: Steve Walton -- even if you don't use the term, reliability must-run, there must be let's say generators in the northwest that need to run to provide reactive power, and some ability to control the price that they charge for running when they're needed to run.

MR. WALTON: In the generation, there's this complex relationship that you develop when you build an ISO. There's a relationship between the generator and the ISO, the generator and the physical owner of the asset, the relationship between the physical asset owner and the RTO, and in the generation integration agreement, which is the link between the generator and the ISO or the RTO. That will include separate provisions that say if you have to have it, it will come on, and there has to be a backup price.

But the normal notion of just paying for people for reliability must-runs on a standardized basis of some sort or other -- I don't know that that's necessary. You have to have the ability to order in an emergency, or when reliability is at risk, to be able to order generators to come on, or to do different things for you. We think we can build that flexibility into those agreements.

MS. FERNANDEZ: In terms of some of the other market power mitigation measures, I kind of sense there's a different philosophy among some of you, or in some of your organizations in terms of, say, bid screens, and what we label demand response proxies, which is there currently is a thousand-dollar bid cap in existence in most of the east.

Are those measures that should be standardized, or that we need to allow for regional variation?

MR. PALIZA: Let me just respond to that in a general way.

In the case of the midwest, during the design process, the market power issue came up in a very strong way. There are some of our stakeholders that feel very strongly that we need to develop mitigation schemes as part of the market design, and incorporate them into the initial implementation.

The market power issues that have been brought to us, the specific issues are dealing with load pockets, especially when there are transmission constraints that prevent power from getting into the load pockets, and the local generators then have an advantage.

We have been examining some of the mitigation schemes that are being used in PJM and New York for some of the purposes. You know, that analysis has not been concluded. But as I said, some of our stakeholders feel strongly that those mitigation schemes need to be developed and incorporated into the design before we go operational.

MR. WALTON: Just to hit the bent nail one more time: you had expected that. But the bid screens and some of the generator bidding rules -- again, they're going to be difficult. When you're standing below the dam and you see water coming over the top and you see water coming through the turbine, you don't know why they are doing that. It could be they're floating a barge downriver. It could be that there's energy that needs to be sold.

So the problem you get into is, if someone -- how can you tell when they bid a price, is that price based on their value of the thinking tomorrow or the next week, or is that based on trying to withhold in order to drive up price? You can't tell the difference. They all look the same.

So that's the challenge we're going to have to come up against with the hydro systems. That's why we keep talking about the recognition of the opportunity cost component of the hydro. So it becomes a much more difficult, I think, and complicated question to answer in this kind of environment than it would be in a thermal environment where you could say, well, I can see your coal pile and I know what it costs you to get your coal there; therefore, I can calculate what your cost is tomorrow.

MS. FERNANDEZ: Most of the bid screens allow some ability to contact the generator, either in advance or for the generator to contact the ISO if the bid is going to look strange and they know it's going to trigger it. Is that something that maybe there's some ways of working it in?

MR. WALTON: As I said, there are probably ways to address this. As I said, it's a more complicated question. You aren't going to be able to answer a simple question with a simple set of rules, because again, their forward view and your forward view could be quite different. You think they're withholding; he says no, I think there's going to be a drought. I'm not going to get any rain or snow.

To some degree, the standard operating plan for the hydro systems helps to address part of that problem. But on the other hand, there are individual judgments project by project as to what they want to get out of that or how they want to exchange the energy or withhold it or move it, and they're going to complicate that process. I don't know the answer beyond that.

MR. O'NEILL: Just to hit the crooked nail again, I think we agree with you. Hydro is truly a difficult issue to sort out. But you can deal with thermal units a lot easier in a lot more straightforward manner.

I think you're right. Hydro can have its own reasons, and they can be very good.

MR. KING: I just want to add: I think you can have a standard framework. And the framework that we talked about yesterday that relied on conduct, impact and then parameters -- you know, you can deal with the regional variation in how you set thresholds, margins and the philosophy that you use to develop reference prices.

I think consultation is an element that should be part of that standard, for the reasons that Stephen brought up and others have talked about. And sometimes the only way you're going to know why somebody bids a certain way is to simply ask them.

We do go one step further, in that we actually conduct field audits as well. In other words, parties do provide us data, and we do have the ability to go in and verify that we are getting the correct data, and that we do understand the picture.

So I think we're comfortable with the consultation process. It works very well. And again I think you can standardize on a framework but allow flexibility in terms of how the parameters are set to deal with unique pocket problems or unique operating limitations. That's where you'll need to allow for some flexibility.

MR. LA PLANTE: One thought on the demand response proxy. We agree that we need a bid cap until there's more demand response. That statement's probably been made thousands of times, maybe hundreds of thousands of times, in these discussions. But we haven't been able to move forward very quickly to get it.

One possible way of helping move it forward would be for the Commission to allow transmission owners to recover costs of installing the meters necessary for real-time response. I think that sort of technology would help move things forward quickly, more quickly at any rate.

CHAIRMAN WOOD: What did that effort cost in Ontario? Do you have a price tag on that? From down to how small of a customer load did you put real-time metering?

MR. SHALABY: Whatever it cost in Canadian dollars.

(Laughter.)

MR. SHALABY: Most customers that are above five megawatts have requirements to have interim meters. It is an expensive effort. I do not have the total dollar number, but the judgment is it's money well-invested. It enables choice and it enables the right charging of folks at the right time.

It's a large effort, but in our judgment it was worth doing. And if you have further interest, I can try and assess an aggregate cost.

CHAIRMAN WOOD: That would be very helpful. I certainly went through that on the retail side. Those arguments are easy to make when your market's opening all the way, as yours is as well. When you're stopping at the wholesale level, you have to look at maybe where those people can participate.

It might be a smaller universe you're talking about, quite frankly, if you had 5 percent of the load able to switch on and off in response to price.

MR. LA PLANTE: The supply curves do look like a hockey stick, so you don't need 100 percent of the market involved. But for customers above a certain level, it would probably give you enough demand response to eliminate the need for bid caps.

CHAIRMAN WOOD: Is the thousand the right number for the time? I was just thinking with Rob back here -- you know, relatively large grocery store, maybe a 200-kilowatt load. You ask them to shut off for an hour at a thousand bucks; 200 bucks, no one will ever take that. Well, maybe in the middle of the night.

But it's supposed to be a proxy for demand.

MR. LA PLANTE: That's very customer-specific. The grocery store might not want to do it, but a factory might be able to do it.

CHAIRMAN WOOD: For 200 bucks?

MR. WALTON: It's interesting to look at this question in terms of what kind of demands can respond, what kind of businesses can. Certain kinds of loads have very high costs of energy: liquid gases, arc furnaces, pot lines for aluminum -- those kinds of processes. Those can have demand responsive kinds of characteristics.

And you get into something like the grocery store, where the energy cost is 1 or 2 percent of their total operating budget, and where even in the evening, where they have refrigeration issues or 24-hour operations, the idea of turning the lights out is pretty low.

So because it's pretty steep if you actually get those high-responsive customers involved, maybe you don't need to worry about the grocery stores, and it's up to them if they want to.

CHAIRMAN WOOD: You just need to find the marginal level.

MR. LA PLANTE: Most of the response to the thousand-dollar cap is really people turning on emergency-type generators or onsite generators they seldom use. I think you're right. For someone to shut their business down, giving them a thousand dollars doesn't really justify shutting the business down for any period of time.

MR. O'NEILL: But I think that Steve in California has a different take on this, that they actually got a lot of response from small customers.

MR. GREENLEAF: Yes. I think over the last year the conservation efforts, which really were responsive -- perhaps delayed, but certainly responsive to price -- there was a tremendous amount. We're looking on the order of something on the order of 11 percent reduction in demand, which was actually incredible.

But I think that's a key point that David raised. There are thresholds as to how much demand response you need. I've heard anywhere, you know, from the 5 to 12 percent range. Once you get that kind of demand response, it's really an effective market power mitigation tool.

So I think you do want to target it and maybe tailor it to this set of customers or whatnot. Generically, you're right. The conservation efforts in California tell you that people do respond to demand.

MR. KING: I just want to add, we had a fairly successful start to our emergency demand response program. We've had several programs in New York. I believe we have a report that is either out or coming out to assess the program from last summer. We'd be happy to forward that on to the Commission.

But we had, during the peak week, an average of about 400 megawatts of response in the real-time program, which helped us significantly. We'd obviously like to see more. But for the first year of the program, we thought it was very good. We've been getting a lot of encouragement, too.

So I would expect to see even a broader participation this coming summer.

CHAIRMAN WOOD: I have one question. What kind of -- shifting gears to RTOs as institutions -- what sort of informal or formal mechanisms do each of the groups have, or propose to have, that allow a customer or group of customers -- basically, if we're talking about flexibility for innovation and customer response, talk to me about how these groups here, I guess, all of which are not-for-profit, respond to what customer needs are, broadly.

MR. GREENLEAF: Very broadly, we have in place a client relations department, which I think in the course of the last three and a half years has been generally responsive to the needs of the market participants -- in this case, the scheduling coordinators with whom we interface.

You know, there's a dialogue there, and that's our primary source of feedback other than specific feedback in the context of stakeholder discussions on specific changes that we're proposing or whatnot. But in general, we get feedback through the client relations department. Obviously, the market participants can speak better than I as to how effective that's been, but that's our primary vehicle for soliciting feedback.

MR. LA PLANTE: We also have a customer service group that's a daily point of contact for participants. There are extensive at least monthly meetings of the NEPOOL Participants Committee, which is the governing body in NEPOOL. Then there are many other meetings on various matters -- market issues, transmission issues, reliability issues -- that the ISO and the stakeholders get together and discuss and decide on issues.

The phone is always ringing with individual calls, concerns and issues.

MR. KING: We also have a very active customer relations department. We've found that market participants like to have the consistency in the people they deal with. So originally when we first set it up, as questions came in, if you called one day, you called one person. If you called another day, you got someone else.

We've kind of moved away from that. We have customers assigned specific reps. We found that customers really do appreciate being able to build a relationship with an individual. So we communicate on that level.

Our customer relations staff also goes out into the field and visits with our customers, and we get a lot of direct feedback that way.

Committee support is something that has evolved. We felt that to make the stakeholder committees function smoothly and provide the feedback that we need, we have to put in the effort to facilitate the meetings, and to be there to interact with the market participants. So we put a great deal more effort into that, and I think it's paid off very well. We've been able to resolve issues and build consensus I think much faster with that approach than when we first started.

So, that's something that I think you really have to work at. But it is worth the effort.

MR. SHALABY: In addition to all of that, which we have in Ontario, customers have seats on the board of directors of the Independent Market Operator. They also know the phone number of the Minister of Energy.

(Laughter.)

MR. PALIZA: We have a client's office, but in addition to that, we have several stakeholder groups that are focused on particular aspects of the MISO operation. For example, we have a MISO congestion management working group that is responsible for the MISO market design. We have an operations support group that focuses on the Day 1 operation: advisory committee, policy subcommittee -- all these stakeholder groups are the way that we collect input, discuss the issues and reach resolution. They are open for anyone to attend, and it's basically a public type of forum.

MR. WALTON: Since we don't exist, we don't have a customer service department yet.

(Laughter.)

MR. WALTON: In the governance structure, we set up an independent board. But there are stakeholder input and voting rights and so on in the various classes. In addition, there's an advisory group that any member or anyone who pays the minimum participates and becomes a member, can participate in that. It was set up so that any party could take their view directly to the board if they wished to.

Beyond that, we've been running a fairly open stakeholder process, and I don't suppose that RTO West, when it forms, will suffer from timid customers.

MR. OTT: I think, obviously, in PJM there's the standard customer relations group. I think the other thing is to build a culture of responsiveness to customers. It starts at the top; the board is more or less elected by members, so it's not a self-perpetuating board. It's elected by members. So to some extent, obviously, the board is interested in serving the members.

I think the other mechanism you have is the ability to form a user group like a demand-side user group that was formed in PJM that more or less can report through the committee structure to the board. So you can get a group of members -- where they're all environmental types and concerns, they all get together in one group, and they can use that group to provide a consistent message.

I think the other area, though -- we actually survey our customers. We go out and do customer satisfaction surveys. But more importantly, the results of that feed back into our salary -- not salary, our bonus structure.

So for instance, like 20 and 30 percent of our bonus depends on us meeting the targets. So we have to have a 97 percent customer satisfaction. Unfortunately, this year it's 96.8, so we did not make it.

(Laughter.)

MR. OTT: That means that all of our bonuses, from the janitor to Phil Harris, more or less, we will take a hit because we didn't meet it. So that's why we're known as the friendly RTO.

(Laughter.)

MR. OTT: We do care, obviously, a lot, and we do have a cultural structure that says, you must care about what the numbers say. Numbers will, you know, never satisfy everyone, and you will -- at times, the RTO has to go to members and say, no. But the point is, at least we listen.

So, setting up the responsiveness, really you have to show the employees it matters. And the way we happened to do it, we set a corporate goal. If you don't meet the corporate goal, part of the incentive salary -- the contestable salary, if you will -- is affected. Plus, the board is member-elected.

So I think that's important.

CHAIRMAN WOOD: On behalf of my colleagues, I want to thank all these two days' worth of wonderful panelists. I really appreciate your time and intelligent, helpful thoughts very much.

(Whereupon, at 4:10 p.m., the meeting was adjourned.)